NOBLE ENERGY INC
Form 10-Q
July 28, 2011

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-Q

x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended June 30, 2011

OR

o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from _____to_____

Commission file number: 001-07964

NOBLE ENERGY, INC.
(Exact name of registrant as specified in its charter)

Delaware	73-0785597
(State or other jurisdiction of incorporation or organization)	(I.R.S. employer identification number)
100 Glenborough Drive, Suite 100 Houston, Texas	77067
(Address of principal executive offices)	(Zip Code)

(281) 872-3100
(Registrant’s telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes x No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required

to submit and post such files).
Yes x No o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of “large accelerated filer”, “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act.

Large accelerated filer x	Accelerated filer o	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
Yes o No x

As of July 8, 2011, there were 176,513,711 shares of the registrant’s common stock,
par value $3.33 1/3 per share, outstanding.

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Part I. Financial Information
Item 1. Financial Statements

Noble Energy, Inc.
Consolidated Statements of Operations
(millions, except per share amounts)
(unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
Revenues				
Oil, Gas and NGL Sales	$895	$710	$1,725	$1,398
Income from Equity Method Investees	48	24	96	50
Other Revenues	11	17	33	36
Total	954	751	1,854	1,484
Costs and Expenses				
Production Expense	155	150	296	289
Exploration Expense	68	52	138	132
Depreciation, Depletion and Amortization	235	215	456	431
General and Administrative	82	63	165	129
Asset Impairments	131	-	139	-
Other Operating (Income) Expense, Net	(11)	41	18	55
Total	660	521	1,212	1,036
Operating Income	294	230	642	448
Other (Income) Expense				
(Gain) Loss on Commodity Derivative Instruments	(143)	(96)	143	(242)
Interest, Net of Amount Capitalized	21	19	37	39
Other Non-Operating (Income) Expense, Net	(9)	(13)	-	(13)
Total	(131)	(90)	180	(216)
Income Before Income Taxes	425	320	462	664
Income Tax Provision	131	116	154	223
Net Income	$294	$204	$308	$441
Earnings Per Share, Basic	$1.66	$1.17	$1.75	$2.53
Earnings Per Share, Diluted	1.61	1.10	1.73	2.44
Weighted Average Number of Shares Outstanding, Basic	176	175	176	175
Weighted Average Number of Shares Outstanding, Diluted	179	178	178	178

The accompanying notes are an integral part of these financial statements.

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Noble Energy, Inc.
Consolidated Balance Sheets
(millions)
(unaudited)

	June 30, 2011	December 31, 2010
ASSETS		
Current Assets		
Cash and Cash Equivalents	$1,527	$1,081
Accounts Receivable, Net	571	556
Other Current Assets	215	201
Total Assets, Current	2,313	1,838
Property, Plant and Equipment		
Oil and Gas Properties (Successful Efforts Method of Accounting)	15,341	14,393
Property, Plant and Equipment, Other	278	263
Total Property, Plant and Equipment, Gross	15,619	14,656
Accumulated Depreciation, Depletion and Amortization	(4,751)	(4,392)
Total Property, Plant and Equipment, Net	10,868	10,264
Goodwill	696	696
Other Noncurrent Assets	462	484
Total Assets	$14,339	$13,282
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts Payable - Trade	$1,072	$927
Other Current Liabilities	430	495
Total Liabilities, Current	1,502	1,422
Long-Term Debt	2,797	2,272
Deferred Income Taxes, Noncurrent	2,188	2,110
Other Noncurrent Liabilities	694	630
Total Liabilities	7,181	6,434
Commitments and Contingencies		
Shareholders' Equity		
Preferred Stock - Par Value $1.00 per share; 4 Million Shares Authorized, None Issued	-	-
Common Stock - Par Value $3.33 1/3 per share; 250 Million Shares Authorized; 196 Million and 195 Million Shares Issued, Respectively	654	651
Additional Paid in Capital	2,446	2,385
Accumulated Other Comprehensive Loss	(86)	(104)
Treasury Stock, at Cost; 19 Million Shares	(640)	(624)
Retained Earnings	4,784	4,540
Total Shareholders' Equity	7,158	6,848
Total Liabilities and Shareholders' Equity	$14,339	$13,282

The accompanying notes are an integral part of these financial statements.

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Noble Energy, Inc.
Consolidated Statements of Cash Flows
(millions)
(unaudited)

	Six Months Ended June 30, 2011	2010
Cash Flows From Operating Activities		
Net Income	$308	$441
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities		
Depreciation, Depletion and Amortization	456	431
Asset Impairments	139	-
Dry Hole Cost	45	54
Deferred Income Taxes	44	85
Dividends (Income) from Equity Method Investees, Net	(5)	(2)
Unrealized (Gain) Loss on Commodity Derivative Instruments	160	(210)
Gain on Divestitures	(26)	-
Other Adjustments for Noncash Items Included in Income	45	24
Changes in Operating Assets and Liabilities		
(Increase) in Accounts Receivable	(32)	(73)
(Increase) Decrease in Other Current Assets	(17)	28
Increase in Accounts Payable	188	102
Increase (Decrease) in Current Income Taxes Payable	(62)	18
Increase (Decrease) in Other Current Liabilities	1	(21)
Other Operating Assets and Liabilities, Net	(15)	(33)
Net Cash Provided by Operating Activities	1,229	844
Cash Flows From Investing Activities		
Additions to Property, Plant and Equipment	(1,261)	(782)
Proceeds from Divestitures	77	-
Central DJ Basin Asset Acquisition	-	(466)
Net Cash Used in Investing Activities	(1,184)	(1,248)
Cash Flows From Financing Activities		
Exercise of Stock Options	26	28
Excess Tax Benefits from Stock-Based Awards	9	16
Dividends Paid, Common Stock	(64)	(63)
Purchase of Treasury Stock	(16)	(12)
Proceeds from Credit Facilities	120	1,165
Repayment of Credit Facilities	(470)	(727)
Proceeds from Issuance of Senior Long-Term Debt, Net	836	-
Settlement of Interest Rate Derivative Instrument	(40)	-
Net Cash Provided By Financing Activities	401	407
Increase in Cash and Cash Equivalents	446	3
Cash and Cash Equivalents at Beginning of Period	1,081	1,014
Cash and Cash Equivalents at End of Period	$1,527	$1,017

The accompanying notes are an integral part of these financial statements.

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Noble Energy, Inc.
Consolidated Statements of Shareholders' Equity
(millions)
(unaudited)

	Common Stock	Additional Paid in Capital	Acumulated Other Comprehensive Loss	Treasury Stock at Cost	Retained Earnings	Total Shareholders' Equity
December 31, 2010	$ 651	$ 2,385	$ (104)	$ (624)	$ 4,540	$ 6,848
Net Income	-	-	-	-	308	308
Stock-based Compensation	-	29	-	-	-	29
Exercise of Stock Options	2	24	-	-	-	26
Tax Benefits Related to Exercise of Stock Options	-	9	-	-	-	9
Restricted Stock Awards, Net	1	(1)	-	-	-	-
Dividends (36 cents per share)	-	-	-	-	(64)	(64)
Changes in Treasury Stock, Net	-	-	-	(16)	-	(16)
Interest Rate Cash Flow Hedges						
Unrealized Change in Fair Value	-	-	15	-	-	15
Net Change in Other	-	-	3	-	-	3
June 30, 2011	$ 654	$ 2,446	$ (86)	$ (640)	$ 4,784	$ 7,158
December 31, 2009	$ 645	$ 2,260	$ (75)	$ (615)	$ 3,942	$ 6,157
Net Income	-	-	-	-	441	441
Stock-based Compensation	-	27	-	-	-	27
Exercise of Stock Options	2	26	-	-	-	28
Tax Benefits Related to Exercise of Stock Options	-	16	-	-	-	16
Restricted Stock Awards, Net	2	(2)	-	-	-	-
Dividends (36 cents per share)	-	-	-	-	(63)	(63)
Changes in Treasury Stock, Net	-	-	-	(12)	-	(12)
Oil and Gas Cash Flow Hedges						
Realized Amounts Reclassified Into Earnings	-	-	6	-	-	6
Interest Rate Cash Flow Hedges						
Unrealized Change in Fair Value	-		(61)			(61)
Net Change in Other	-	-	2	-	-	2
June 30, 2010	$ 649	$ 2,327	$ (128)	$ (627)	$ 4,320	$ 6,541

The accompanying notes are an integral part of these financial statements.

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Noble Energy, Inc.
Notes to Consolidated Financial Statements
(unaudited)

Note 1. Organization and Nature of Operations

Noble Energy, Inc. (Noble Energy, we or us) is a leading independent energy company engaged in worldwide crude oil and natural gas exploration and production. Our key operating areas are onshore in the US, primarily in the Denver-Julesberg (DJ) Basin, in the deepwater Gulf of Mexico, offshore Eastern Mediterranean, and offshore West Africa.

Note 2. Basis of Presentation

Presentation The accompanying unaudited consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the US (US GAAP) for interim financial information and with the instructions to Form 10-Q and Article 10 of Regulation S-X. Accordingly, they do not include all of the information and notes required by US GAAP for complete financial statements. The accompanying consolidated financial statements at June 30, 2011 and December 31, 2010 and for the three and six months ended June 30, 2011 and 2010 contain all normally recurring adjustments considered necessary for a fair presentation of our financial position, results of operations, cash flows and shareholders' equity for such periods. Operating results for the three and six months ended June 30, 2011 are not necessarily indicative of the results that may be expected for the year ending December 31, 2011. Certain reclassifications of amounts previously reported have been made to conform to current year presentations. These consolidated financial statements should be read in conjunction with the consolidated financial statements and accompanying notes included in our Annual Report on Form 10-K for the year ended December 31, 2010.

Consolidation Our consolidated accounts include our accounts and the accounts of our wholly-owned subsidiaries. In addition, we use the equity method of accounting for investments in entities that we do not control but over which we exert significant influence. All significant intercompany balances and transactions have been eliminated upon consolidation.

Estimates The preparation of consolidated financial statements in conformity with US GAAP requires us to make a number of estimates and assumptions relating to the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ significantly from those estimates.

Statements of Operations Information Other statements of operations information is as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
(millions)				
Other Revenues				
Electricity Sales (1)	$11	$16	$32	$35
Other	-	1	1	1
Total	$11	$17	$33	$36
Production Expense				
Lease Operating Expense	$99	$100	$191	$188
Production and Ad Valorem Taxes	38	34	70	67

Transportation Expense	18	16	35	34
Total	$155	$150	$296	$289
Other Operating (Income) Expense, Net				
Deepwater Gulf of Mexico Moratorium Expense (2)	$1	$26	$19	$26
Electricity Generation Expense (1)	9	7	26	17
Gain on Divestitures (3)	(25)	-	(26)	-
Other, Net	4	8	(1)	12
Total	$(11)	$41	$18	$55
Other Non-Operating (Income) Expense, Net				
Deferred Compensation (Income) Expense (4)	$(7)	$(13)	$3	$(11)
Interest Income	(2)	(2)	(5)	(4)
Other (Income) Expense, Net	-	2	2	2
Total	$(9)	$(13)	$-	$(13)

(1) Electricity sales include sales from the Machala power plant located in Machala, Ecuador, through May 2011. Electricity generation expense includes all operating and non-operating expenses associated with the plant, including depreciation and changes in the allowance for doubtful accounts. See footnote (3) below.

(2) Amounts relate to rig stand-by expense incurred prior to receiving permit to resume drilling activities in the deepwater Gulf of Mexico in 2011 and costs to terminate a deepwater Gulf of Mexico drilling rig contract due to the deepwater Gulf of Mexico drilling moratorium in 2010.

(3) Amount relates primarily to the transfer of assets to the Ecuadorian government. We received cash proceeds of $73 million for the transfer of our offshore Amistad field assets and Block 3 production sharing contract (PSC), which was terminated by the government of Ecuador on November 25, 2010, and the assignment of the Machala Power Electricity concession and its associated assets. Our net book value for the assets had been reduced due to previous reductions for impairments, resulting in a gain of $26 million before tax. We did not consider the property disposition material for discontinued operations presentation.

(4) Amount represents increases (decreases) in the fair value of shares of our common stock held in a rabbi trust.

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Noble Energy, Inc.
Notes to Consolidated Financial Statements
(unaudited)

Balance Sheet Information   Other balance sheet information is as follows:

(millions)	June 30, 2011	December 31, 2010
Accounts Receivable, Net		
Commodity Sales	$270	$291
Joint Interest Billings	241	259
Other	68	33
Allowance for Doubtful Accounts (1)	(8)	(27)
Total	$571	$556
Other Current Assets		
Inventories, Current	$122	$112
Commodity Derivative Assets, Current	5	62
Deferred Income Taxes, Net, Current	33	8
Probable Insurance Claims (2)	25	-
Prepaid Expenses and Other Assets, Current	30	19
Total	$215	$201
Other Noncurrent Assets		
Equity Method Investments	$292	$285
Mutual Fund Investments	118	112
Other Assets, Noncurrent	52	87
Total	$462	$484

(1) The decrease from December 31, 2010 in the allowance for doubtful accounts is due to transfer of assets to the Ecuadorian government. See footnote (3) above.
(2) We expect to receive insurance proceeds related to the Leviathan-2 appraisal well offshore Israel.

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Noble Energy, Inc.
Notes to Consolidated Financial Statements
(unaudited)

(millions)	June 30, 2011	December 31, 2010
Other Current Liabilities		
Production and Ad Valorem Taxes	$125	$ 110
Commodity Derivative Liabilities, Current	61	24
Interest Rate Derivative Liability, Current	-	63
Income Taxes Payable	28	90
Asset Retirement Obligations, Current	45	45
Interest Payable	55	36
Current Portion of FPSO Lease Obligation	21	-
Other	95	127
Total	$430	$ 495
Other Noncurrent Liabilities		
Deferred Compensation Liabilities, Noncurrent	$241	$ 229
Asset Retirement Obligations, Noncurrent	213	208
Accrued Benefit Costs, Noncurrent	79	76
Commodity Derivative Liabilities, Noncurrent	119	51
Other	42	66
Total	$694	$ 630

Recently Issued Accounting Standards Update In May 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update No. 2011-04: Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs (ASU 2011-04). ASU 2011-04 clarifies application of fair value measurement and disclosure requirements and is effective for annual periods beginning after December 15, 2011. We are currently evaluating the provisions of ASU 2011-04 and assessing the impact, if any, it may have on our financial position and results of operations.

In June 2011, the FASB issued Accounting Standards Update No. 2011-05: Comprehensive Income (Topic 220): Presentation of Comprehensive Income (ASU 2011-05). ASU 2011-05 provides that an entity that reports items of other comprehensive income has the option to present comprehensive income in either one continuous financial statement or two consecutive financial statements. ASU 2011-05 is effective for annual periods beginning after December 15, 2011.

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Noble Energy, Inc.
Notes to Consolidated Financial Statements
(unaudited)

Note 3. Asset Impairments

Pre-tax (non-cash) asset impairment charges were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
(millions)				
East Texas (Onshore US)	$116	$-	$116	$-
Other (Primarily Onshore US)	15	-	23	-
Total	$131	$-	$139	$-

Due to field performance combined with a low natural gas price environment, we determined that the carrying amounts of certain of our onshore US developments, primarily in East Texas, were not recoverable from future cash flows and, therefore, were impaired. The assets were written down to their estimated fair values, which were determined using discounted cash flow models. See Note 6. Fair Value Measurements and Disclosures.

Note 4. Debt

Our debt consists of the following:

	June 30, 2011		December 31, 2010	
	Debt	Interest Rate	Debt	Interest Rate
(millions, except percentages)				
Credit Facility, due December 9, 2012	$-	-	$350	0.57 %
5¼% Senior Notes, due April 15, 2014	200	5.25 %	200	5.25 %
8¼% Senior Notes, due March 1, 2019	1,000	8.25 %	1,000	8.25 %
7¼% Notes, due October 15, 2023	100	7.25 %	100	7.25 %
8% Senior Notes, due April 1, 2027	250	8.00 %	250	8.00 %
6% Senior Notes, due March 1, 2041	850	6.00 %	-	-
7¼% Senior Debentures, due August 1, 2097	84	7.25 %	84	7.25 %
FPSO Lease Obligation (1)	346	-	295	-
Total	2,830		2,279	
Unamortized Discount	(12)		(7)	
Total Debt, Net of Discount	2,818		2,272	
Less Amounts Due Within One Year (1)	(21)		-	
Long-Term Debt Due After One Year	$2,797		$2,272	

(1) We have entered into an agreement to lease a floating production, storage and offloading vessel (FPSO) to be used in the development of the Aseng field, offshore Equatorial Guinea. The amount of the FPSO lease obligation is based on the discounted present value of future minimum lease payments and the percentage of construction activities completed as of the reporting dates, and therefore does not reflect future minimum lease payments. The increase in the FPSO lease obligation is a non-cash financing activity. Amounts due within one year equal the

amount by which the FPSO lease obligation is expected to be reduced during the next 12 months as lease payments begin. We currently expect production to commence at year end 2011.

Debt Issuance   On February 18, 2011, we closed an offering of $850 million senior unsecured notes receiving net proceeds of $836 million, after deducting discount and underwriting fees. The notes are due March 1, 2041, and pay interest semi-annually at 6%. Total debt issuance costs of approximately $9 million were incurred and are being amortized to expense over the term of the notes. Approximately $470 million of the net proceeds were used to repay outstanding indebtedness under our revolving credit facility and the balance of the proceeds will be used for general corporate purposes. The notes are senior unsecured debt and rank pari passu with any of our other senior unsecured indebtedness with respect to the payment of both principal and interest.

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Noble Energy, Inc.
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(unaudited)

Annual Debt Maturities and FPSO Lease Payments   Annual maturities of outstanding debt and estimated annual FPSO lease payments are as follows:

(millions)	Debt Principal Payments	FPSO Lease Payments
June 30, 2011		
2011	$ -	$ -
2012	-	72
2013	-	72
2014	200	72
2015	-	72
Thereafter	2,284	209
Total	$ 2,484	$ 497

Note 5. Derivative Instruments and Hedging Activities

Objective and Strategies for Using Derivative Instruments   In order to reduce commodity price uncertainty and enhance the predictability of cash flows relating to the marketing of our crude oil and natural gas, we enter into crude oil and natural gas price hedging arrangements with respect to a portion of our expected production. The derivative instruments we use include variable to fixed price commodity swaps, two-way and three-way collars and basis swaps.

The fixed price swap, two-way collar, and basis swap contracts entitle us (floating price payor) to receive settlement from the counterparty (fixed price payor) for each calculation period in amounts, if any, by which the settlement price for the scheduled trading days applicable for each calculation period is less than the fixed strike price or floor price. We would pay the counterparty if the settlement price for the scheduled trading days applicable for each calculation period is more than the fixed strike price or ceiling price. The amount payable by us, if the floating price is above the fixed or ceiling price, is the product of the notional quantity per calculation period and the excess of the floating price over the fixed or ceiling price in respect of each calculation period. The amount payable by the counterparty, if the floating price is below the fixed or floor price, is the product of the notional quantity per calculation period and the excess of the fixed or floor price over the floating price in respect of each calculation period.

A three-way collar consists of a two-way collar contract combined with a put option contract sold by us with a strike price below the floor price of the two-way collar. We receive price protection at the purchased put option floor price of the two-way collar if commodity prices are above the sold put option strike price. If commodity prices fall below the sold put option strike price, we receive the cash market price plus the delta between the two put option strike prices. This type of instrument allows us to capture more value in a rising commodity price environment, but limits our benefits in a downward commodity price environment.

We also enter into forward contracts or swap agreements to hedge exposure to interest rate risk.

While these instruments mitigate the cash flow risk of future reductions in commodity prices or increases in interest rates, they may also curtail benefits from future increases in commodity prices or decreases in interest rates.

See Note 6. Fair Value Measurements and Disclosures for a discussion of methods and assumptions used to estimate the fair values of our derivative instruments.

Counterparty Credit Risk Derivative instruments expose us to counterparty credit risk. Our commodity derivative instruments are currently with a diversified group of highly rated major banks or market participants, and we control our level of financial exposure. Our commodity derivative contracts are executed under master agreements which allow us, in the event of default, to elect early termination of all contracts with the defaulting counterparty. If we choose to elect early termination, all asset and liability positions with the defaulting counterparty would be net settled at the time of election.

We monitor the creditworthiness of our counterparties. However, we are not able to predict sudden changes in counterparties' creditworthiness. In addition, even if such changes are not sudden, we may be limited in our ability to mitigate an increase in counterparty credit risk. Possible actions would be to transfer our position to another counterparty or request a voluntary termination of the derivative contracts resulting in a cash settlement. Should one of these financial counterparties not perform, we may not realize the benefit of some of our derivative instruments under lower commodity prices or higher interest rates, and could incur a loss.

Interest Rate Derivative Instrument In January 2010, we entered into an interest rate forward starting swap to effectively fix the cash flows related to interest payments on our anticipated debt issuance. On February 15, 2011 we settled the interest rate swap, which had a net liability position of $40 million. Approximately $26 million, net of tax, was recorded in accumulated other comprehensive loss (AOCL) and is being reclassified to interest expense over the term of the notes. The ineffective portion of the interest rate swap was de minimis. See Note 4. Debt.

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Noble Energy, Inc.
Notes to Consolidated Financial Statements
(unaudited)

Unsettled Derivative Instruments
As of June 30, 2011, we had entered into the following crude oil derivative instruments:

Period	Type of Contract	Index	Bbls Per Day	Swaps Weighted Average Fixed Price	Weighted Average Short Put Price	Collars Weighted Average Floor Price	Weighted Average Ceiling Price
Instruments Entered Into as of June 30, 2011							
2011	Swaps	NYMEX WTI (1)	5,000	$ 85.52	$ -	$ -	$ -
2011	Two-Way Collars	NYMEX WTI	13,000	-	-	80.15	94.63
2011	Three-Way Collars	NYMEX WTI	12,000	-	58.33	78.33	100.71
2012	Swaps	NYMEX WTI	5,000	91.84	-	-	-
2012	Swaps	Dated Brent	8,000	89.06	-	-	-
2012	Three-Way Collars	NYMEX WTI	23,000	-	61.09	83.04	101.66
2012	Three-Way Collars	Dated Brent	3,000	-	70.00	95.83	105.00
2013	Swaps	Dated Brent	3,000	98.03	-	-	-
2013	Three-Way Collars	NYMEX WTI	5,000	-	65.00	85.00	113.63
2013	Three-Way Collars	Dated Brent	12,000	-	75.83	97.50	125.93

(1) West Texas Intermediate

As of June 30, 2011, we had entered into the following natural gas derivative instruments:

Period	Type of Contract	Index	MMBtu Per Day	Swaps Weighted Average Fixed Price	Weighted Average Short Put Price	Collars Weighted Average Floor Price	Weighted Average Ceiling Price
Instruments Entered Into as of June 30, 2011							
2011	Swaps	NYMEX HH (1)	25,000	$ 6.41	$ -	$ -	$ -
2011	Two-Way Collars	NYMEX HH	140,000	-	-	5.95	6.82
2011	Three-Way Collars	NYMEX HH	50,000	-	4.00	5.00	6.70

2012	Swaps	NYMEX HH	30,000	5.10	-	-	-
2012	Three-Way Collars	NYMEX HH	110,000	-	4.44	5.25	6.66
2013	Swaps	NYMEX HH	30,000	5.25	-	-	-
2013	Three-Way Collars	NYMEX HH	50,000	-	4.00	5.25	5.59

(1) Henry Hub

As of June 30, 2011, we had entered into the following natural gas basis swaps:

Period	Index	Index Less Differential	MMBtu Per Day	Weighted Average Differential
2011	IFERC CIG (1)	NYMEX HH	140,000	$ (0.70)
2012	IFERC CIG	NYMEX HH	150,000	(0.52)

(1) Colorado Interstate Gas – Northern System

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Noble Energy, Inc.
Notes to Consolidated Financial Statements
(unaudited)

Fair Value Amounts and Gains and Losses on Derivative Instruments The fair values of derivative instruments in our consolidated balance sheets were as follows:

Fair Value of Derivative Instruments

	Asset Derivative Instruments				Liability Derivative Instruments			
	June 30, 2011		December 31, 2010		June 30, 2011		December 31, 2010	
(millions)	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Commodity Derivative Instruments (Not Designated as Hedging Instruments)	Current Assets	$ 5	Current Assets	$ 62	Current Liabilities	$ 61	Current Liabilities	$ 24
	Noncurrent Assets	-	Noncurrent Assets	-	Noncurrent Liabilities	119	Noncurrent Liabilities	51
Interest Rate Derivative Instruments (Designated as Hedging Instruments)	Current Assets	-	Current Assets	-	Current Liabilities	-	Current Liabilities	63
Total		$ 5		$ 62		$ 180		$ 138

The effect of derivative instruments on our consolidated statements of operations was as follows:

Commodity Derivative Instruments Not Designated as Hedging Instruments
Amount of (Gain) Loss on Derivative Instruments Recognized in Income

	Three Months Ended June 30,		Six Months Ended June 30,	
(millions)	2011	2010	2011	2010
Realized Mark-to-Market Gain	$ (1)	$ (33)	$ (17)	$ (32)
Unrealized Mark-to-Market (Gain) Loss	(142)	(63)	160	(210)
Total (Gain) Loss on Commodity Derivative Instruments	$ (143)	$ (96)	$ 143	$ (242)

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Derivative Instruments in Cash Flow Hedging Relationships

	Amount of (Gain) Loss on Derivative Instruments Recognized in Other Comprehensive (Income) Loss		Amount of (Gain) Loss on Derivative Instruments Reclassified from Accumulated Other Comprehensive Loss	
	2011	2010	2011	2010
(millions)				
Three Months Ended June 30,				
Commodity Derivative Instruments in Previously Designated Cash Flow Hedging Relationships (1)				
Crude Oil Derivative Instruments	$-	$-	$-	$4
Natural Gas Derivative Instruments	-	-	-	-
Interest Rate Derivative Instruments in Cash Flow Hedging Relationships	-	83	-	-
Total	$-	$83	$-	$4
Six Months Ended June 30,				
Commodity Derivative Instruments in Previously Designated Cash Flow Hedging Relationships (1)				
Crude Oil Derivative Instruments	$-	$-	$-	$9
Natural Gas Derivative Instruments	-	-	-	1
Interest Rate Derivative Instruments in Cash Flow Hedging Relationships	(23)	94	1	-
Total	$(23)	$94	$1	$10

(1) Includes effect of commodity derivative instruments previously accounted for as cash flow hedges. All net derivative gains and losses that were deferred in AOCL as a result of previous cash flow hedge accounting, had been reclassified to earnings by December 31, 2010.

AOCL at June 30, 2011 included deferred losses of $27 million, net of tax, related to interest rate derivative instruments. This amount will be reclassified to earnings as an adjustment to interest expense over the terms of our senior notes due April 2014 and March 2041. Approximately $2 million of deferred losses (net of tax) will be reclassified to earnings during the next 12 months and will be recorded as an increase in interest expense.

Note 6. Fair Value Measurements and Disclosures

Assets and Liabilities Measured at Fair Value on a Recurring Basis

Certain assets and liabilities are measured at fair value on a recurring basis in our consolidated balance sheets. The following methods and assumptions were used to estimate the fair values:

Cash, Cash Equivalents, Accounts Receivable and Accounts Payable   The carrying amounts approximate fair value due to the short-term nature or maturity of the instruments.

Mutual Fund Investments   Our mutual fund investments, which primarily include assets held in a rabbi trust, consist of various publicly-traded mutual funds that include investments ranging from equities to money market instruments. The fair values are based on quoted market prices for identical assets.

Commodity Derivative Instruments   Our commodity derivative instruments consist of variable to fixed price commodity swaps, two-way and three-way collars and basis swaps. We estimate the fair values of these instruments based on published forward commodity price curves as of the date of the estimate. The discount rate used in the discounted cash flow projections is based on published LIBOR rates, Eurodollar futures rates and interest swap rates. The fair values of commodity derivative instruments in an asset position include a measure of counterparty nonperformance risk, and the fair values of commodity derivative instruments in a liability position include a measure of our own nonperformance risk, each based on the current published credit default swap rates. In addition, for collars, we estimate the option values of the put options sold (for three-way collars) and the contract floors and ceilings (for two-way and three-way collars) using an option pricing model which takes into account market volatility, market prices and contract terms. See Note 5. Derivative Instruments and Hedging Activities.

Interest Rate Derivative Instrument   We estimated the fair value of our forward starting swap based on published interest rate yield curves as of the date of the estimate. The fair values of interest rate derivative instruments in an asset position include a measure of counterparty nonperformance risk, and the fair values of interest rate derivative instruments in a liability position include a measure of our own nonperformance risk, each based on the current published credit default swap rates. See Note 5. Derivative Instruments and Hedging Activities.

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Deferred Compensation Liability   The value is dependent upon the fair values of mutual fund investments and shares of our common stock held in a rabbi trust. See Mutual Fund Investments above.

Measurement information for assets and liabilities that are measured at fair value on a recurring basis was as follows:

	Fair Value Measurements Using				
(millions)	Quoted Prices in Active Markets (Level 1) (1)	Significant Other Observable Inputs (Level 2) (2)	Significant Unobservable Inputs (Level 3) (3)	Adjustment (4)	Fair Value Measurement
June 30, 2011					
Financial Assets					
Mutual Fund Investments	$118	$ -	$ -	$ -	$ 118
Commodity Derivative Instruments	-	69	-	(64)	5
Financial Liabilities					
Commodity Derivative Instruments	-	(244)	-	64	(180)
Portion of Deferred Compensation Liability Measured at Fair Value	(184)	-	-	-	(184)
December 31, 2010					
Financial Assets					
Mutual Fund Investments	$112	$ -	$ -	$ -	$ 112
Commodity Derivative Instruments	-	106	-	(44)	62
Financial Liabilities					
Commodity Derivative Instruments	-	(119)	-	44	(75)
Interest Rate Derivative Instrument	-	(63)	-	-	(63)
Portion of Deferred Compensation Liability Measured at Fair Value	(178)	-	-	-	(178)

(1) Level 1 measurements are fair value measurements which use quoted market prices (unadjusted) in active markets for identical assets or liabilities. We use Level 1 inputs when available as Level 1 inputs generally provide the most reliable evidence of fair value.
(2) Level 2 measurements are fair value measurements which use inputs, other than quoted prices included within Level 1, which are observable for the asset or liability, either directly or indirectly.
(3) Level 3 measurements are fair value measurements which use unobservable inputs.
(4) Amount represents the impact of master netting agreements that allow us to net cash settle asset and liability positions with the same counterparty.

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

Certain assets and liabilities are measured at fair value on a nonrecurring basis in our consolidated balance sheets. The following methods and assumptions were used to estimate the fair values:

Asset Impairments   We determined that the carrying amounts of certain onshore US assets, were not recoverable from future cash flows and, therefore, were impaired. The assets were reduced to their estimated fair values. Information about the impaired assets is as follows:

	Fair Value Measurements Using				
Description (millions)	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Net Book Value (1)	Total Pre-tax (Non-cash) Impairment Loss
Three Months Ended June 30, 2011					
Impaired Oil and Gas Properties	$ -	$ -	$ 29	$ 160	$ 131
Six Months Ended June 30, 2011					
Impaired Oil and Gas Properties	-	-	32	171	139

(1) Amount represents net book value at date of assessment.

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The fair values of the properties were determined as of the date of the assessment using discounted cash flow models. The discounted cash flows were based on management's expectations for the future. Inputs included estimates of future oil and gas production, commodity prices based on published forward commodity price curves as of the date of the estimate, estimated operating and development costs, and a risk-adjusted discount rate. See Note 3. Asset Impairments.

Additional Fair Value Disclosures

Debt The fair value of fixed-rate debt is estimated based on the published market prices for the same or similar issues. There was no floating-rate debt outstanding at June 30, 2011. The carrying amount of floating-rate debt at December 31, 2010 approximated fair value because the interest rate paid on such debt was set for periods of three months or less. See Note 4. Debt.

Fair value information regarding our debt is as follows:

	June 30, 2011		December 31, 2010	
(millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-Term Debt, Net of Unamortized Discount (1)	$2,472	$2,886	$1,977	$2,302

(1) Excludes FPSO lease obligation.

Note 7. Capitalized Exploratory Well Costs

Changes in capitalized exploratory well costs are as follows and exclude amounts that were capitalized and subsequently expensed in the same period:

(millions)	Six Months Ended June 30, 2011
Capitalized Exploratory Well Costs, Beginning of Period	$ 426
Additions to Capitalized Exploratory Well Costs Pending Determination of Proved Reserves	114
Reclassified to Proved Oil and Gas Properties Based on Determination of Proved Reserves (1)	(53)
Capitalized Exploratory Well Costs Charged to Expense	(15)
Capitalized Exploratory Well Costs, End of Period	$ 472

(1) Includes $13 million related to the Flyndre project in the North Sea.

The following table provides an aging of capitalized exploratory well costs (suspended well costs) based on the date the drilling was completed and the number of projects for which exploratory well costs have been capitalized for a period greater than one year since the completion of drilling:

June 30,

(millions)	2011	December 31, 2010
Exploratory Well Costs Capitalized for a Period of One Year or Less	$153	$148
Exploratory Well Costs Capitalized for a Period Greater Than One Year After Completion of Drilling	319	278
Balance at End of Period	$472	$426
Number of Projects with Exploratory Well Costs That Have Been Capitalized for a Period Greater Than One Year After Completion of Drilling	10	9

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The following table provides a further aging of those exploratory well costs that have been capitalized for a period greater than one year since the completion of drilling as of June 30, 2011:

		Suspended Since		
(millions)	Total	2010	2009	2008 & Prior
Country/Project				
Offshore Equatorial Guinea				
Blocks O and I	$102	$3	$14	$85
Offshore Cameroon				
YoYo	34	-	-	34
Offshore Israel				
Dalit	20	-	20	-
Deepwater Gulf of Mexico				
Deep Blue	75	56	19	-
Gunflint	49	-	-	49
Redrock	17	-	-	17
North Sea				
Selkirk	20	-	-	20
Other				
3 projects of $10 million or less each	2	2	-	-
Total	$319	$61	$53	$205

Blocks O and I   Blocks O and I are crude oil, natural gas and natural gas condensate discoveries. During second quarter 2011 we drilled a successful appraisal well at the Carmen/Diega prospect.

YoYo   YoYo is a 2007 natural gas and condensate discovery. We have acquired and processed additional 3-D seismic information.

Dalit   Dalit is a 2009 natural gas discovery. We are currently working with our partners on a cost-effective development plan.

Deep Blue   Deep Blue (Green Canyon Block 723) is a significant exploratory well, which began drilling during 2009. The well found hydrocarbon pay in multiple intervals. When the deepwater Gulf of Mexico moratorium was announced in May 2010, we were required to suspend sidetrack drilling activities. We recently obtained approval for a drilling permit and plan to resume exploration drilling during third quarter of 2011.

Gunflint   Gunflint (Mississippi Canyon Block 948) is a 2008 crude oil discovery. Our plans to conduct appraisal drilling activities in 2010 were delayed by the deepwater Gulf of Mexico moratorium. Once a drilling permit is approved, we plan to resume drilling activities. We are also reviewing host platform options.

Redrock   Redrock (Mississippi Canyon Block 204) is a 2006 natural gas/condensate discovery and is currently considered a co-development candidate with Raton South (Mississippi Canyon Block 292). We are in the process of developing Raton South as a subsea tieback to a host platform at Viosca Knoll Block 900. We plan to develop

Redrock after Raton South commences production, which is currently expected to occur by the end of 2011.

Selkirk   The Selkirk project is located in the UK sector of the North Sea. Capitalized costs to date primarily consist of the cost of drilling an exploratory well. We are currently working with our partners on a cost-effective development plan, including selection of a host facility.

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Note 8. Asset Retirement Obligations

Asset retirement obligations consist primarily of estimated costs of dismantlement, removal, site reclamation and similar activities associated with our oil and gas properties. Changes in asset retirement obligations were as follows:

	Six Months Ended June 30,	
	2011	2010
(millions)		
Asset Retirement Obligations, Beginning Balance	$253	$232
Liabilities Incurred	1	14
Liabilities Settled	(12)	(9)
Revision of Estimate	6	4
Accretion Expense	10	9
Asset Retirement Obligations, Ending Balance	$258	$250

Liabilities settled in 2011 related primarily to deepwater and shelf properties in the Gulf of Mexico.

Liabilities incurred in 2010 were due to the Central DJ Basin asset acquisition.

Accretion expense is included in depreciation, depletion and amortization (DD&A) expense in the consolidated statements of operations.

Note 9. Employee Benefit Plans

We have a noncontributory, tax-qualified defined benefit pension plan covering employees who were hired prior to May 1, 2006. We also have an unfunded, nonqualified restoration plan that provides the pension plan formula benefits that cannot be provided by the qualified pension plan because of pay deferrals and the compensation and benefit limitations imposed on the pension plan by the Internal Revenue Code of 1986, as amended. Net periodic benefit cost related to the retirement and restoration plans was as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
(millions)				
Service Cost	$ 4	$ 4	$ 8	$ 7
Interest Cost	3	3	7	7
Expected Return on Plan Assets	(4)	(3)	(8)	(7)
Other	2	1	3	3
Net Periodic Benefit Cost	$ 5	$ 5	$ 10	$ 10

During the six months ended June 30, 2011, we made cash contributions of $5 million to the pension plan.

Note 10. Stock-Based Compensation

We recognized stock-based compensation expense as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
(millions)				
Stock-Based Compensation Expense	$14	$13	$29	$27
Tax Benefit Recognized	(5)	(5)	(10)	(9)

During the six months ended June 30, 2011, we granted stock options and awarded shares of restricted stock (subject to service conditions) as follows:

	Number Granted/Awarded	Weighted Average Fair Value
Stock Options	974,993	$ 30.23
Shares of Restricted Stock	398,827	$ 90.41

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On April 26, 2011, our stockholders approved the amendment and restatement of our 1992 Stock Option and Restricted Stock Plan to increase the number of shares of common stock authorized for issuance under the plan from 24 million to 31 million and modify certain plan provisions.

Note 11. Basic and Diluted Earnings Per Share

Basic earnings per share of common stock is computed using the weighted average number of shares of common stock outstanding during each period. The diluted earnings per share of common stock may include the effect of outstanding stock options, shares of restricted stock, or shares of our common stock held in a rabbi trust except in periods in which there is a net loss. The following table summarizes the calculation of basic and diluted earnings per share:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
(millions, except per share amounts)				
Net Income	$294	$204	$308	$441
Earnings Adjustment from Assumed Conversion of Dilutive Shares of Common Stock in Rabbi Trust (1)	(4)	(9)	-	(7)
Net Income Used for Diluted Earnings Per Share Calculation	$290	$195	$308	$434
Weighted Average Number of Shares Outstanding, Basic	176	175	176	175
Incremental Shares from Assumed Conversion of Dilutive Stock Options, Restricted Stock and Shares of Common Stock in Rabbi Trust	3	3	2	3
Weighted Average Number of Shares Outstanding, Diluted	179	178	178	178
Earnings Per Share, Basic	$1.66	$1.17	$1.75	$2.53
Earnings Per Share, Diluted	1.61	1.10	1.73	2.44
Number of antidilutive stock options, shares of restricted stock and shares of common stock in rabbi trust excluded from calculation above	2	2	3	2

(1) The diluted earnings per share calculation includes a decrease to net income related to a deferred compensation gain from shares of our common stock held in a rabbi trust. When dilutive, the deferred compensation gain or loss (net of tax) is excluded from net income while the shares of our common stock held in the rabbi trust are included in the outstanding diluted share count.

Note 12. Income Taxes

The income tax provision consists of the following:

	Three Months Ended June 30,	Six Months Ended June 30,

	2011	2010	2011	2010
(millions)				
Current	$97	$59	$110	$138
Deferred	34	57	44	85
Total Income Tax Provision	$ 131	$116	$154	$223
Effective Tax Rate	31 %	36 %	33 %	34 %

Our effective tax rate decreased for the first six months of 2011 as compared with the first six months of 2010. This was due to increased earnings from equity method subsidiaries, which has the impact of decreasing the effective rate when we have pre-tax income. This decrease in the rate was partially offset by the impact of the changes in Israeli tax law discussed below and by a $14 million increase in the valuation allowance against our deferred tax asset for foreign tax credits during 2011. In addition, the rate for the first six months of 2010 was higher due to a nondeductible allocation of goodwill to assets sold.

Changes in Israeli Tax Law   In March 2011, the Israeli government enacted the Oil Profits Taxation Law, 2011, which imposes additional income tax on oil and gas production. The Israeli government also repealed the percentage depletion deduction and made certain changes to the rules for deducting tangible and intangible development costs. We expect these changes to increase our 2011 consolidated effective income tax rate by approximately two percentage points. We expect no remeasurement of our deferred tax assets or liabilities as of December 31, 2010.

Changes in UK Tax Law Also in March 2011, the UK government announced that the Finance Bill 2011 will increase the rate of the Supplementary Charge levied on oil and gas income in the UK from 20% to 32% effective March 24, 2011. This change became law on July 19, 2011 and will increase the tax rate on our UK oil and gas income from 50% to 62% and increase our 2011 consolidated effective income tax rate by approximately four percentage points. The change will also result in a remeasurement of our UK deferred tax liability as of December 31, 2010 to reflect the higher effective rate. These changes will be reflected in our balance sheet and results of operations in the third quarter of 2011.

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Years Remaining Open to Examination In our major tax jurisdictions, the earliest years remaining open to examination are as follows: US – 2006, Equatorial Guinea – 2007, Israel – 2008, UK – 2007, the Netherlands – 2009, and China – 2006.

Note 13. Comprehensive Income

Comprehensive income includes net income and certain items recorded directly to shareholders' equity and classified as AOCL. Comprehensive income was calculated as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
(millions)				
Net Income	$294	$204	$308	$441
Other Items of Comprehensive Income (Loss)				
Oil and Gas Cash Flow Hedges				
Realized Losses Reclassified Into Earnings	-	4	-	10
Less Tax Provision	-	(1)	-	(4)
Interest Rate Cash Flow Hedges				
Unrealized Change in Fair Value	-	(83)	23	(94)
Less Tax Provision	-	29	(8)	33
Net Change in Other	1	1	3	2
Other Comprehensive Income (Loss)	1	(50)	18	(53)
Comprehensive Income	$295	$154	$326	$388

Note 14. Segment Information

We have operations throughout the world and manage our operations by country. The following information is grouped into five components that are all primarily in the business of crude oil and natural gas exploration, development, and acquisition: the United States; West Africa (Equatorial Guinea, Cameroon, Senegal and Guinea-Bissau); Eastern Mediterranean (Israel and Cyprus); the North Sea (UK and the Netherlands); and Other International and Corporate. Other International includes China, Ecuador (through May 2011), and new ventures.

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(millions)	Consolidated	United States	West Africa	Eastern Mediterranean	North Sea	Other Int'l and Corporate
Three Months Ended June 30, 2011						
Revenues from Third Parties	$ 906	$553	$118	$ 76	$112	$47
Income from Equity Method Investees	48	-	48	-	-	-
Total Revenues	954	553	166	76	112	47
DD&A	235	187	7	7	24	10
Asset Impairments	131	131	-	-	-	-
Gain on Divestiture (1)	(25)	-	-	-	-	(25)
Gain on Commodity Derivative Instruments	(143)	(142)	(1)	-	-	-
Income (Loss) Before Income Taxes	425	250	116	57	70	(68)
Three Months Ended June 30, 2010						
Revenues from Third Parties	$ 731	$459	$118	$ 48	$62	$44
Reclassification from AOCL (2)	(4)	(4)	-	-	-	-
Income from Equity Method Investees	24	-	24	-	-	-
Total Revenues	751	455	142	48	62	44
DD&A	215	177	11	7	11	9
Gain on Commodity Derivative Instruments	(96)	(81)	(15)	-	-	-
Income (Loss) Before Income Taxes	320	181	127	33	36	(57)
Six Months Ended June 30, 2011						
Revenues from Third Parties	$ 1,758	$1,058	$248	$ 128	$226	$98
Income from Equity Method Investees	96	-	96	-	-	-
Total Revenues	1,854	1,058	344	128	226	98
DD&A	456	354	17	11	52	22
Asset Impairments	139	137	-	-	2	-
Gain on Divestiture (1)	(26)	(1)	-	-	-	(25)
Loss on Commodity Derivative Instruments	143	50	93	-	-	-
Income (Loss) Before Income Taxes	462	213	190	96	138	(175)

Six Months Ended June 30, 2010						
Revenues from Third Parties	$ 1,444	$968	$179	$ 81	$128	$88
Reclassification from AOCL (2)	(10)	(10)	-	-	-	-
Income from Equity Method Investees	50	-	50	-	-	-
Total Revenues	1,484	958	229	81	128	88
DD&A	431	358	19	11	26	17
Gain on Commodity Derivative Instruments	(242)	(227)	(15)	-	-	-
Income (Loss) Before Income Taxes	664	470	194	59	73	(132)
June 30, 2011						
Goodwill	$ 696	$696	$-	$ -	$-	$-
Total Assets	14,339	9,607	2,531	1,276	728	197
December 31, 2010						
Goodwill	696	696	-	-	-	-
Total Assets	13,282	9,091	2,270	919	770	232

(1) Amount relates primarily to the transfer of our Ecuador assets to the Ecuadorian government. See Note 2. Basis of Presentation.

(2) Revenues include decreases resulting from hedging activities. The decreases resulted from hedge gains and losses that were deferred in AOCL, as a result of previous cash flow hedge accounting, and subsequently reclassified to revenues. All hedge gains and losses had been reclassified to revenues by December 31, 2010.

Note 15. Commitments and Contingencies

Legal Proceedings We are involved in various legal proceedings in the ordinary course of business. These proceedings are subject to the uncertainties inherent in any litigation. We are defending ourselves vigorously in all such matters and we believe that the ultimate disposition of such proceedings will not have a material adverse effect on our financial position, results of operations or cash flows.

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Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

EXECUTIVE OVERVIEW

We are an independent energy company engaged in global crude oil and natural gas exploration and production. Our strategy is to achieve growth in earnings and cash flows through the continued expansion of a high quality portfolio of assets that is diversified among US and international projects, crude oil and natural gas, and near, medium and long-term opportunities.

Our accompanying consolidated financial statements, including the notes thereto, contain detailed information that should be referred to in conjunction with the following discussion.

Our financial results for second quarter 2011 included:

- net income of $294 million, as compared with $204 million for second quarter 2010;
- asset impairment charges of $131 million as compared with none for second quarter 2010;
- pre-tax gain of $26 million on divestitures as compared with none for second quarter 2010;
- gain on commodity derivative instruments of $143 million (including unrealized mark-to-market gain of $142 million) as compared with a gain on commodity derivative instruments of $96 million (including unrealized mark-to-market gain of $63 million) for second quarter 2010;
- diluted earnings per share of $1.61, as compared with $1.10 for second quarter 2010;
- cash flow provided by operating activities of $745 million, as compared with $256 million for second quarter 2010;
- capital spending, on a cash basis, of $683 million, as compared with $399 million for second quarter of 2010;
- increased liquidity to over $3.6 billion, with $1.5 billion in cash at the end of the period; and
- ratio of debt-to-book capital of 28% as compared with 25% at December 31, 2010.

Operational events for second quarter 2011 included:

United States Onshore

- produced a record 59 MBoe/d in the DJ Basin;
- drilled longest-ever horizontal Niobrara well in the DJ Basin with over 9,100 foot lateral in the Wattenberg field;

Deepwater Gulf of Mexico

- announced discovery at Santiago and increased the expected Galapagos project's initial net production to over 10 MBbl/d of oil;

International

- sold 174 MMcf/d of natural gas in Israel, up 44% from the second quarter last year;
- accelerated startup of Aseng, offshore Equatorial Guinea, targeting first production by year end 2011; and
- completed transfer of assets and exit from Ecuador.

Exploration Program

We have significant remaining exploration potential, primarily in the onshore US, deepwater Gulf of Mexico, offshore West Africa, offshore Eastern Mediterranean and other international areas where we hold acreage positions. We anticipate testing multiple exploration opportunities before the end of 2011. Updates of our significant exploration activities are as follows:

North America Onshore   We continue to acquire seismic information and appraise our acreage in the DJ Basin and other onshore areas.

Santiago (Deepwater Gulf of Mexico) In May 2011, we announced a crude oil discovery at the Santiago exploration prospect. Santiago is the third discovery in the Galapagos project, along with Santa Cruz and Isabela. We are in the process of completing Santiago and expect production to commence in early 2012.

Deep Blue (Deepwater Gulf of Mexico)   We recently obtained approval for a drilling permit and expect to resume exploration drilling during third quarter of 2011.

Carmen/Diega (Offshore West Africa)   During the second quarter of 2011, we drilled a successful appraisal well which encountered both crude oil and natural gas. We have drilled two sidetracks, each of which encountered hydrocarbons. We are evaluating the results and formulating a development plan.

New Ventures   We have expanded our global exploration inventory by joining a venture to explore the AGC Profond block offshore Senegal and Guinea-Bissau (30% non-operated working interest). The block covers more than two million gross acres and includes a number of identified prospects. The joint venture has drilled the Kora-1 exploration well. The well did not result in commercial quantities of hydrocarbons; however, there are a number of prospects in the area. We are working with our partners on future exploration plans and have the option to act as operator going forward. We are also processing recently acquired 3D seismic for Nicaragua and 2D seismic for France.

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Major Development Projects

During second quarter 2011, we continued to advance our major development projects, which we expect to deliver significant growth over the next several years. Updates on our significant development projects are as follows:

DJ Basin (US Onshore) We have increased our horizontal drilling activity targeting the Niobrara formation, spudding 20 horizontal wells and completing 11 during the quarter. We are currently running four horizontal drilling rigs and plan to bring a fifth horizontal rig into the field during third quarter.

Galapagos(Deepwater Gulf of Mexico) Installation of topside equipment at the host facility and subsea tiebacks for the Santa Cruz, Isabela and Santiago wells are progressing. We currently expect production to commence in early 2012.

Gunflint (Deepwater Gulf of Mexico) Once a drilling permit is approved, we plan to conduct appraisal drilling to help define the extent of the reservoir and a potential development scenario.

Aseng (Offshore Equatorial Guinea) FPSO conversion is progressing, subsea installation is underway, and we currently expect production to commence at year end 2011.

Alen (Offshore Equatorial Guinea) We continue to progress the Alen project. Platform construction is underway, development drilling rigs have been contracted, and we currently expect production to commence by the end of 2013.

Tamar (Offshore Israel) During second quarter of 2011, we completed batch drilling of the top hole sections of the five development wells. We have awarded all major contracts for subsea installations and completed a survey of the pipeline route. Platform fabrication is proceeding, and Tamar remains on schedule for commissioning in late 2012.

In addition, we have sanctioned the development of the Noa field, offshore Israel, to supplement our natural gas supply to Israel until the start-up of Tamar. Noa will be developed as a subsea tieback to the existing Mari-B platform. We currently expect to commence field development in third quarter 2011, with first production expected in the second half of 2012.

West Africa Gas Project (Offshore Equatorial Guinea) The Equatorial Guinea Ministry of Mines, Industry and Energy is considering the development of an integrated gas project (Integrated Project) which includes upstream gas projects, the required gas transportation system, and a second LNG train. A Coordinating Committee was formed to determine the viability and scope of the Integrated Project. We have been appointed chair of the Coordinating Committee.

Leviathan (Offshore Israel) We are evaluating potential development scenarios for the Leviathan natural gas discovery and planning pre-FEED (front end engineering design) activities.

In May 2011, we ended drilling operations at the Leviathan-2 appraisal well location. During the drilling process, we identified water flowing to the sea floor from the wellbore. We are monitoring the wellbore and there are no indications of any hydrocarbons in the produced water. Drilling did not reach the depth of the targeted gas intervals discovered in the Leviathan-1 well. The incident was a covered event under our well control insurance; therefore, we expect to recover most of the costs from insurance, subject to a deductible.

We have resumed the Leviathan natural gas appraisal drilling program and spud the Leviathan-3 well in late June 2011.

Asset Impairments

During second quarter 2011, we recorded asset impairment charges of $131 million related to certain of our onshore US oil and gas assets. The impairments were primarily due to field performance combined with a low natural gas price environment. Future decreases in forward natural gas prices or other factors, such as significant increases in development or operating costs or unsatisfactory drilling results, could result in additional impairment charges. See Item 1. Financial Statements – Note 3. Asset Impairments.

Divestitures

In May 2011, we completed the transfer of our assets in Ecuador to various government-affiliated entities. We received compensation for the offshore Amistad field assets and Block 3 PSC which was terminated by the government of Ecuador on November 25, 2010, as well as for the Machala Power Electricity concession and its associated assets and recorded a gain of approximately $26 million. See Item 1. Financial Statements – Note 2. Basis of Presentation.

Sales Volumes

On a BOE basis, total sales volumes were 2% lower second quarter 2011 as compared with second quarter 2010, and our mix of sales volumes was 39% global liquids,32% international natural gas, and 29% US natural gas. International sales volumes were higher in Israel and the North Sea. US production decreased slightly year to year due to sale of non-core properties in 2010. Equatorial Guinea sales volumes were lower as there were fewer liftings during the period as compared with 2010. Our volumes for second quarter 2011 did not include natural gas in Ecuador, where our PSC was terminated in late 2010.

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Commodity Price Changes and Hedging

Average realized crude oil prices for second quarter 2011 increased 43% as compared with second quarter 2010 and were driven by stronger global crude oil markets.

Total average realized natural gas prices for second quarter 2011 increased 11% as compared with second quarter 2010 primarily due to higher international natural gas pricing.

We have hedged approximately 49% of our expected global crude oil production and 60% of our expected domestic natural gas production for the remainder of 2011.

OPERATING OUTLOOK

Our expected crude oil, natural gas and NGL production for 2011 may be impacted by several factors including:

- overall level and timing of capital expenditures which, as discussed below and dependent upon our drilling success, are expected to maintain our near-term production volumes;
- timing of significant project completion and initial production;
- ongoing development activity in the Wattenberg area and horizontal drilling in the Niobrara formation in the DJ Basin;
- natural field decline in the deepwater Gulf of Mexico, Gulf Coast and Mid-Continent areas of our US operations and in the North Sea;
- potential legislative and regulatory changes in deepwater Gulf of Mexico operating and safety requirements for producing activities due to the 2010 explosion of the Deepwater Horizon drilling rig and subsequent oil spill (Deepwater Horizon Incident);
- variations in sales volumes of natural gas from the Alba field in Equatorial Guinea related to potential downtime at the methanol, LPG and/or LNG plants;
- Israeli demand for electricity which affects demand for natural gas as fuel for power generation, market growth and competing deliveries of natural gas from Egypt;
- performance of a compression project at the Mari-B field, offshore Israel;
- variations in North Sea sales volumes due to potential FPSO downtime and timing of liftings;
- potential hurricane-related volume curtailments in the deepwater Gulf of Mexico and Gulf Coast areas;
- potential winter storm-related volume curtailments in the Rocky Mountain area of our US operations;
- potential pipeline and processing facility capacity constraints in the Rocky Mountain area of our US operations;
- potential purchases of producing properties; and
- potential divestments of non-core, non-strategic operating assets.

2011 Capital Investment Program

We have adjusted our 2011 total capital program from approximately $2.7 billion to approximately $3 billion. Over a third of the $300 million increase is related to new high-impact international exploration opportunities, with the remainder supporting the continued expansion of the Wattenberg horizontal Niobrara development program, the acceleration of the Aseng project in Equatorial Guinea, and the addition of a new near-term gas development project at Noa field in Israel.

The addition of the offshore Senegal and Guinea-Bissau opportunity as well as the updated timing of a Cyprus exploration well (now planned to spud in the fourth quarter) comprises the majority of the higher exploration capital for 2011.

We continue to expand our Niobrara drilling program at Wattenberg, with plans to bring a fifth horizontal rig into the field in the middle part of the third quarter of 2011. As a result of the additional rig and continued efficiencies, we anticipate drilling around 85 horizontal Niobrara wells in the DJ Basin in 2011, up approximately 30% from original estimates. Offshore Israel, we are proceeding with development of the Noa field, with the drilling and completion of two wells planned to commence in the third quarter of 2011 (first production is expected in the second half of 2012).

In addition, we are continuing to progress our liquid developments at Aseng and Alen, offshore Equatorial Guinea. First production at Aseng is now targeted for year end 2011.

In addition to the capital investment program discussed above, we expect to accrue approximately $70 million for the Aseng FPSO lease obligation during 2011.

We expect that the 2011 capital investment program will be funded from cash flows from operations, cash on hand, and borrowings under our revolving credit facility and/or other financing such as our issuance of long-term debt in first quarter 2011. See Liquidity and Capital Resources.

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We will evaluate the level of capital spending throughout the year based on the following factors, among others:

- commodity prices;
- cash flows from operations;
- operating and development costs and possible inflationary pressures;
- permitting activity in the deepwater Gulf of Mexico;
- potential changes in the fiscal regimes of the US and other countries in which we operate;
- impact of implementation of the Dodd-Frank Act on our business practices, including, among others, requirements regarding the posting of cash collateral in hedging transactions;
- drilling results;
- property acquisitions and divestitures; and
- potential legislative or regulatory changes regarding the use of hydraulic fracturing.

Current Global Economic Situation, Changes in Fiscal Regimes and Market Regulations

The recovery from the global financial crisis has been slow and uneven. Due to higher unemployment rates and slower economic growth, many governments are facing demands to increase social spending. Increased spending on public entitlement and/or economic stimulus programs, coupled with a reduced tax base, has resulted in significant budget deficits in many countries. Against this backdrop, global commodity prices have recovered significantly.

In order to address negative fiscal situations and initiate deficit reduction measures, many governments are seeking additional revenue sources, including increases in government take from oil and gas projects. Future economic and political changes in the US or other countries in which we operate could result in governments enacting additional taxes and/or other market interventions, which could be detrimental to oil and gas companies.

During the first six months of 2011, fiscal regime changes occurred in both Israel and the UK.

Israel In March 2011, the Israeli government enacted the Oil Profits Taxation Law, 2011, which imposes additional income tax on oil and gas production. The Israeli government also repealed the percentage depletion deduction and made certain changes to the rules for deducting tangible and intangible development costs. We currently expect these changes to increase our 2011 consolidated income tax expense by approximately $25 million and increase our 2011 consolidated effective income tax rate by approximately two percentage points. We expect no remeasurement of our deferred tax assets or liabilities as of December 31, 2010. The impact of the changes in Israel’s tax law is reflected in our balance sheet and results of operations at June 30, 2011.

The change in Israel’s fiscal regime may negatively impact our future operations by reducing future project profitability, as compared with profitability under the previous fiscal regime, and potentially reducing the economic attractiveness of exploration activities.

UK Also in March 2011, the UK government announced that the Finance Bill 2011 will increase the rate of the Supplementary Charge levied on oil and gas income in the UK from 20% to 32% effective March 24, 2011. This change became law on July 19, 2011 and will increase the tax rate on our UK oil and gas income from 50% to 62%, resulting in an increase of approximately $54 million in our 2011 consolidated income tax expense and an increase in our 2011 consolidated effective income tax rate by approximately four percentage points. The estimated increases in our consolidated income tax expense and effective income tax rate include the impact of remeasuring our UK deferred tax liability as of December 31, 2010 to reflect the higher effective rate. These changes will be reflected in our balance sheet and results of operations in the third quarter of 2011.

See Item 1. Financial Statements – Note 12. Income Taxes.

Risk and Insurance Program Update

Our business is subject to all of the operating risks normally associated with the exploration, production, gathering, processing and transportation of crude oil and natural gas, including hurricanes, blowouts, well cratering and fire, any of which could result in damage to, or destruction of, oil and natural gas wells or formations or production facilities and other property and injury to persons. As protection against financial loss resulting from many, but not all of these operating hazards, we maintain insurance coverage, including certain physical damage, business interruption (loss of production), employer's liability, comprehensive general liability and worker's compensation insurance. We maintain insurance at levels that we believe are appropriate and consistent with industry practice and we regularly review our potential risks of loss and the cost and availability of insurance and revise our insurance program accordingly.

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For example, in certain international locations (including Equatorial Guinea and Israel) we carry business interruption insurance for loss of revenue arising from physical damage to our facilities caused by fire and natural disasters. The coverage is subject to customary deductibles, waiting periods and recovery limits.

In the Gulf of Mexico, we self-insure for windstorm exposure. Our Gulf of Mexico assets are primarily subsea operations; therefore, our windstorm exposure is limited. In addition, the cost of windstorm insurance continues to be very expensive and coverage amounts are limited. We believe it is more cost-effective for us to self-insure these assets. As a result, we are responsible for substantially all windstorm-related damages to our Gulf of Mexico assets.

In accordance with industry practice, oil and gas well owners generally indemnify drilling rig contractors against certain risks, such as those arising from property and environmental losses, pollution from sources such as oil spills, or contamination resulting from well blowout or fire or other uncontrolled flow of hydrocarbons. Most of our domestic and international drilling contracts contain such indemnification clauses. In addition, oil and gas well owners typically assume all costs of well control in the event of an uncontrolled well. We currently carry insurance protection for our net share of any potential financial losses occurring as a result of events such as the Deepwater Horizon Incident. This protection consists of $500 million of well control, pollution cleanup and consequential damages coverage and $326 million of additional pollution cleanup and consequential damages coverage, which also covers third party personal injury and death. Consequently, if we were to experience an accident similar to the Deepwater Horizon Incident, our total coverage for cleanup and consequential damages would be $826 million for our share, subject to reduction for claims related to well control and third party damages.

We expect the future availability and cost of insurance will be impacted by the Japanese earthquake and subsequent tsunami as well as by the Deepwater Horizon Incident. Impacts could include tighter underwriting standards, limitations on scope and amount of coverage, and higher premiums, and will depend, in part, on future changes in laws and regulations regarding exploration and production activities in the Gulf of Mexico, including possible increases in liability caps for claims of damages from oil spills. We anticipate that current changes in the types of coverage available in the insurance market will result in lower effective coverages and/or the incurrence of higher premiums to achieve past levels of coverage.

During 2010, various Congressional committees began pursuing legislation to increase or remove liability caps for deepwater drilling. The current $75 million liability limit under the Oil Pollution Act may be materially increased or lifted in its entirety. Such a requirement would ultimately require a company to maintain either a much higher level of insurance coverage than was standard for the industry in the past, or a financial position large enough that a company could settle its own damage claims. We anticipate that, at a minimum, less insurance coverage will be available and at a higher cost. We continue to monitor the legislative and regulatory response to the Deepwater Horizon Incident and its impact on the insurance market and our overall risk profile. Accordingly, we may adjust our risk and insurance program to provide protection at insured levels that reflect our perception of the cost of risk relative to frequency and severity of the exposure.

Deepwater drilling entails inherent risks. We have a risk assessment program that analyzes safety and environmental hazards and establishes procedures, work practices, training programs and equipment requirements, including monitoring and maintenance rules, for continuous improvement. We have a strong safety performance record and continue to manage our risks and operations such that the likelihood of a significant accident or spill is remote. However, if an event occurs that is not covered by insurance or not fully protected by insured limits, it could have a material adverse impact on our results of operations, cash flows and financial condition.

Oil Spill Response Preparedness

We maintain membership in Clean Gulf Associates (CGA), a nonprofit association of production and pipeline companies operating in the Gulf of Mexico. On behalf of its membership, CGA has contracted with Helix Energy Solutions Group (Helix) for the provision of subsea intervention, containment, capture and shut-in capacity for deepwater Gulf of Mexico exploration wells. The system, known as the Helix Fast Response System (HFRS), at full production capacity, can process up to 55 MBbl/d of oil, 70 MBbl/d of liquids and 95 MMcf/d of natural gas, at 10,000 pounds per square inch (psi) in water depths to 8,000 feet. The HFRS has recently been enhanced with the addition of a 15,000 psi-gauge intervention capping stack designed to handle extremely high-pressure, deeper wells in the deepwater Gulf of Mexico. We have entered into a separate utilization agreement with Helix which specifies the asset day rates should the HFRS system be deployed.

Recently Issued Accounting Standards Update

See Item 1. Financial Statements – Note 2. Basis of Presentation.

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RESULTS OF OPERATIONS

Revenues

Revenues were as follows:

(millions)	2011	2010	Increase from Prior Year
Three Months Ended June 30,			
Oil, Gas and NGL Sales	$ 895	$ 710	26 %
Income from Equity Method Investees	48	24	100 %
Other Revenues	11	17	(35 %)
Total	$ 954	$ 751	27 %
Six Months Ended June 30,			
Oil, Gas and NGL Sales	$ 1,725	$ 1,398	23 %
Income from Equity Method Investees	96	50	92 %
Other Revenues	33	36	(8 %)
Total	$ 1,854	$ 1,484	25 %

Changes in revenues are discussed below.

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Oil, Gas and NGL Sales Average daily sales volumes and average realized sales prices were as follows:

	Sales Volumes				Average Realized Sales Prices		
	Crude Oil & Condensate (MBbl/d)	Natural Gas (MMcf/d)	NGLs (MBbl/d)	Total (MBoe/d) (1)	Crude Oil & Condensate (Per Bbl)	Natural Gas (Per Mcf)	NGLs (Per Bbl)
Three Months Ended June 30, 2011							
United States	37	378	15	115	$ 101.99	$ 4.21	$ 50.03
Equatorial Guinea (2)	11	233	-	50	114.80	0.27	-
Israel	-	174	-	29	-	4.81	-
North Sea	10	6	-	11	119.61	8.28	-
China	3	-	-	3	109.96	-	-
Total Consolidated Operations	61	791	15	208	107.53	3.22	50.03
Equity Investees (3)	2	-	5	7	115.23	-	75.83
Total Operations	63	791	20	215	$ 107.76	$ 3.22	$ 56.65
Three Months Ended June 30, 2010							
United States (4)	38	414	13	120	$ 75.00	$ 3.89	$ 39.37
Equatorial Guinea (2)	16	224	-	54	76.10	0.27	-
Israel	-	121	-	20	-	4.33	-
North Sea	9	7	-	10	75.22	4.53	-
Ecuador (5)	-	27	-	4	-	-	-
China	4	-	-	4	76.05	-	-
Total Consolidated Operations	67	793	13	212	75.36	2.91	39.37
Equity Investees (3)	2	-	5	7	74.22	-	50.32
Total Operations	69	793	18	219	$ 75.33	$ 2.91	$ 42.52
Six Months Ended June 30, 2011							
United States	37	380	14	114	$ 97.15	$ 4.14	$ 48.98
Equatorial Guinea (2)	12	240	-	52	108.57	0.27	-
Israel	-	157	-	26	-	4.54	-
North Sea	10	7	-	12	112.47	7.74	-
China	4	-	-	4	102.61	-	-
Total Consolidated Operations	63	784	14	208	102.20	3.06	48.98
Equity Investees (3)	2	-	5	7	109.89	-	74.16
Total Operations	65	784	19	215	$ 102.41	$ 3.06	$ 56.06
Six Months Ended June 30, 2010							
United States (4)	39	399	13	118	$ 74.39	$ 4.64	$ 42.12
Equatorial Guinea (2)	12	209	-	47	75.16	0.27	-
Israel	-	104	-	17	-	4.28	-
North Sea	9	7	-	10	76.15	4.97	-
Ecuador (5)	-	28	-	5	-	-	-
China	4	-	-	4	74.24	-	-
Total Consolidated Operations	64	747	13	201	74.77	3.32	42.12
Equity Investees (3)	2	-	5	7	74.96	-	53.33
Total Operations	66	747	18	208	$ 74.77	$ 3.32	$ 45.11

(1) Natural gas is converted on the basis of six Mcf of gas per one barrel of oil equivalent. This ratio reflects an energy content equivalency and not a price or revenue equivalency. Given commodity price differentials, the

price for a barrel of oil equivalent for natural gas is significantly less than the price for a barrel of oil.

(2) Natural gas from the Alba field in Equatorial Guinea is under contract for $0.25 per MMBtu to a methanol plant, an LPG plant and an LNG plant. The methanol and LPG plants are owned by affiliated entities accounted for under the equity method of accounting.

(3) Volumes represent sales of condensate and LPG from the Alba plant in Equatorial Guinea. See Income from Equity Method Investees below.

(4) Average realized crude oil and condensate prices reflect reductions of $1.35 per Bbl for second quarter 2010 and $1.34 per Bbl for the first six months of 2010 from hedging activities.

Average realized natural gas prices reflect a reduction of $0.01 per Mcf for the first six months of 2010 from hedging activities. The average realized natural gas price for the second quarter of 2010 was not impacted by hedging activities, as the net deferred amounts reclassified from AOCL were de minimis.

The price reductions resulted from hedge gains/losses that were previously deferred in AOCL. All hedge gains or losses had been reclassified to revenues by December 31, 2010.

(5) Our Block 3 PSC was terminated by the Ecuadorian government on November 25, 2010. Intercompany natural gas sales for 2010 were eliminated for accounting purposes. Electricity sales (through May 2011) are included in other revenues. See Item 1. Financial Statements – Note 2. Basis of Presentation.

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If the realized gains and losses on commodity derivative instruments, which are included in (gain) loss on commodity derivative instruments in our consolidated statements of operations, had been included in oil and gas revenues, the effect on average realized prices would have been as follows:

	Commodity Price Increase (Decrease)			
	2011		2010	
	Crude Oil & Condensate (Per Bbl)	Natural Gas (Per Mcf)	Crude Oil & Condensate (Per Bbl)	Natural Gas (Per Mcf)
Three Months Ended June 30,				
United States	$(6.67)	0.67	$0.12	$0.96
Equatorial Guinea	-	-	(1.81)	-
Total Consolidated Operations	(4.04)	0.32	(0.37)	0.52
Total Operations	(3.92)	0.32	(0.36)	0.52
Six Months Ended June 30,				
United States	$(4.72)	0.71	$(0.20)	$0.51
Equatorial Guinea	-	-	(1.78)	-
Total Consolidated Operations	(2.77)	0.35	(0.47)	0.28
Total Operations	(2.69)	0.35	(0.46)	0.28

An analysis of revenues from sales of crude oil, natural gas and NGLs is as follows:

	Sales Revenues			
	Crude Oil & Condensate	Natural Gas	NGLs	Total
(millions)				
Three Months Ended June, 2010	$460	$202	$48	$710
Changes due to				
Increase (Decrease) in Sales Volumes	(42)	7	6	(29)
Increase in Sales Prices Before Hedging	174	22	14	210
Change in Amounts Reclassified from AOCL	4	-	-	4
Three Months Ended June 30, 2011	$596	$231	$68	$895
Six Months Ended June 30, 2010	$867	$432	$99	$1,398
Changes due to				
Increase (Decrease) in Sales Volumes	(15)	39	9	33
Increase (Decrease) in Sales Prices Before Hedging	304	(37)	17	284
Change in Amounts Reclassified from AOCL	9	1	-	10
Six Months Ended June 30, 2011	$1,165	$435	$125	$1,725

Crude oil and condensate sales – Revenues from crude oil and condensate sales increased during the second quarter and first six months of 2011 as compared with 2010 due to the following:

- increases in average realized prices;
- higher sales volumes in the DJ Basin attributable to ongoing development activity in the Wattenberg area and horizontal drilling in the Niobrara formation;

- higher sales volumes attributable to the Central DJ Basin asset acquisition that closed in March 2010; and
- an increase in North Sea sales volumes primarily as a result of additional deliverability at the Dumbarton complex, including two Lochranza wells which began producing mid and late 2010;

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partially offset by

- decreases in sales volumes from the Gulf Coast and Mid-Continent areas due to natural field decline;
- a decrease in onshore US volumes due to the sale of certain Oklahoma and Illinois Basin assets in 2010; and
- lower sales volumes in Equatorial Guinea as compared with the second quarter of 2010, due to a lower number of liftings.

Revenues from crude oil and condensate sales included deferred losses of $4 million for the second quarter of 2010 and $9 million for the first six months of 2010 reclassified from AOCL related to commodity derivative instruments previously accounted for as cash flow hedges. As of December 31, 2010, there were no further amounts related to commodity derivative instruments remaining to be reclassified from AOCL to crude oil revenues.

Natural gas sales – Revenues from natural gas sales increased during the second quarter and first six months of 2011 as compared with 2010 due to the following:

- higher natural gas prices during second quarter 2011 primarily due to increases in sales prices in Israel which benefit from strong global liquids markets;
- an increase in Israel sales volumes due to an increase in demand for our natural gas driven by higher electricity production and lower levels of competitor natural gas imports from Egypt;
- higher sales volumes in the DJ Basin attributable to ongoing vertical and horizontal drilling in the Wattenberg area;
- higher sales volumes attributable to the Central DJ Basin asset acquisition that closed in March 2010;
- higher sales volumes in Equatorial Guinea as compared with the first six months of 2010, during which time the Alba field experienced a planned shut-down for facilities maintenance and repair; and
- an increase in North Sea sales volumes primarily as a result of increased deliverability at the Dumbarton complex, including two Lochranza wells which began producing mid and late 2010.

partially offset by:

- a decrease in onshore US sales volumes due to the sale of certain Oklahoma and Illinois Basin assets in 2010; and
- decreases in sales volumes from the deepwater Gulf of Mexico, Gulf Coast and Mid-Continent areas due to natural field decline.

Revenues from natural gas sales included deferred loss of $1 million for the first six months of 2010 reclassified from AOCL related to commodity derivative instruments previously accounted for as cash flow hedges. Revenues for the second quarter of 2010 included de minimis amounts reclassified from AOCL. As of December 31, 2010, there were no further amounts related to commodity derivative instruments remaining to be reclassified from AOCL to natural gas revenues.

NGL sales – Most of our US NGL production is from the Wattenberg area and deepwater Gulf of Mexico. NGL sales revenues increased during the second quarter and first six months of 2011 as compared with 2010 due to higher realized prices and a slight increase in sales volumes due to ongoing development activity.

Income from Equity Method Investees We have a 45% interest in Atlantic Methanol Production Company, LLC, which owns and operates a methanol plant and related facilities and a 28% interest in Alba Plant LLC, which owns and operates a liquefied petroleum gas processing plant. Both plants are located onshore on Bioko Island in Equatorial Guinea. Equity method investments are included in other noncurrent assets in our consolidated balance sheets, our share of earnings is reported as income from equity method investees in our consolidated statements of operations, and our share of dividends is reported within cash flows from operating activities in our consolidated statements of cash flows.

The increase in income from equity method investees for the second quarter and first six months of 2011 as compared with 2010 was due to increases in average realized condensate, LPG and methanol prices due to global economic recovery, and increases in condensate and methanol sales volumes. Condensate and LPG sales volumes and average realized prices are included in the average daily sales volumes and average realized sales prices table above.

Methanol sales volumes and prices were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
Methanol Sales Volumes (Mmgal)	39	34	78	69
Methanol Sales Prices (per gallon)	$1.01	$0.84	$1.02	$0.83

Other Revenues   Other revenues include electricity sales and other revenues from operating activities. See Item 1. Financial Statements – Note 2. Basis of Presentation.

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Operating Costs and Expenses

Operating costs and expenses were as follows:

(millions)	2011	2010	Increase (Decrease) from Prior Year
Three Months Ended June 30,			
Production Expense	$155	$150	3 %
Exploration Expense	68	52	31 %
Depreciation, Depletion and Amortization	235	215	9 %
General and Administrative	82	63	30 %
Asset Impairments	131	-	N/M
Other Operating (Income) Expense, Net	(11)	41	N/M
Total	$660	$521	27 %
Six Months Ended June 30,			
Production Expense	$296	$289	2 %
Exploration Expense	138	132	5 %
Depreciation, Depletion and Amortization	456	431	6 %
General and Administrative	165	129	28 %
Asset Impairments	139	-	N/M
Other Operating (Income) Expense, Net	18	55	(67 %)
Total	$1,212	$1,036	17 %

N/M The percentage change is not meaningful.

Changes in operating costs and expenses are discussed below.

Production Expense Components of production expense were as follows:

(millions, except unit rate)	Total per BOE (1)	Total	United States	Equatorial Guinea	Israel	North Sea	Other Int'l, Corporate
Three Months Ended June 30, 2011							
Lease Operating Expense (2)	$5.23	$99	$60	$ 14	$4	$16	$ 5
Production and Ad Valorem Taxes	1.99	38	27	-	-	-	11
Transportation Expense	0.95	18	14	-	-	3	1
Total Production Expense	$8.17	$155	$101	$ 14	$4	$19	$ 17

Three Months Ended June 30, 2010							
Lease Operating Expense (2)	$5.18	$100	$68	$ 13	$3	$11	$ 5
Production and Ad Valorem Taxes	1.75	34	28	-	-	-	6
Transportation Expense	0.87	16	15	-	-	1	-
Total Production Expense	$7.80	$150	$111	$ 13	$3	$12	$ 11
Six Months Ended June 30, 2011							
Lease Operating Expense (2)	$5.07	$191	$122	$ 23	$7	$28	$ 11
Production and Ad Valorem Taxes	1.85	70	52	-	-	-	18
Transportation Expense	0.95	35	30	-	-	4	1
Total Production Expense	$7.87	$296	$204	$ 23	$7	$32	$ 30
Six Months Ended June 30, 2010							
Lease Operating Expense (2)	$5.15	$188	$133	$ 20	$4	$22	$ 9
Production and Ad Valorem Taxes	1.84	67	57	-	-	-	10
Transportation Expense	0.93	34	30	-	-	3	1
Total Production Expense	$7.92	$289	$220	$ 20	$4	$25	$ 20

(1)Consolidated unit rates exclude sales volumes and expenses attributable to equity method investees.

(2)Lease operating expense includes oil and gas operating costs (labor, fuel, repairs, replacements, saltwater disposal and other related lifting costs) and workover expense.

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For the second quarter and first six months of 2011, total production expense increased as compared with 2010 due to the following:

- an increase in US lease operating expense due to higher sales volumes from the Wattenberg area due to ongoing development activities;
- increases in Equatorial Guinea, Israel, and North Sea lease operating expense due to higher sales volumes, as discussed above; and
- an increase in China production taxes due to higher commodity prices;

partially offset by:

- a decrease in US lease operating expense due to the sale of certain Oklahoma and Illinois Basin assets in 2010; and
- a decrease in US production taxes due to lower crude oil sales volumes related to the sale of certain Oklahoma assets in 2010 and natural field decline in the Gulf Coast and Mid-Continent areas.

Oil and Gas Exploration Expense Components of oil and gas exploration expense were as follows:

(millions)	Total	United States	West Africa (1)	Eastern Mediter-ranean (2)	North Sea	Other Int'l, Corporate (3)
Three Months Ended June 30, 2011						
Dry Hole Cost	$23	$(2)	$25	$-	$-	$-
Seismic	13	7	1	3	-	2
Staff Expense	25	7	2	-	1	15
Other	7	7	-	-	-	-
Total Exploration Expense	$68	$19	$28	$3	$1	$17
Three Months Ended June 30, 2010						
Dry Hole Cost	$15	$15	$-	$-	$-	$-
Seismic	13	7	4	2	-	-
Staff Expense	19	5	1	1	-	12
Other	5	5	-	-	-	-
Total Exploration Expense	$52	$32	$5	$3	$-	$12
Six Months Ended June 30, 2011						
Dry Hole Cost	$45	$20	$25	$-	$-	$-
Seismic	39	23	1	3	-	12
Staff Expense	43	12	3	-	1	27
Other	11	11	-	-	-	-
Total Exploration Expense	$138	$66	$29	$3	$1	$39
Six Months Ended June 30, 2010						
Dry Hole Cost	$54	$51	$3	$-	$-	$-
Seismic	35	29	4	2	-	-
Staff Expense	34	8	3	1	1	21
Other	9	9	-	-	-	-

Total Exploration Expense	$132	$97	$10	$3	$1	$21

(1) West Africa includes Equatorial Guinea, Cameroon, Senegal and Guinea-Bissau.

(2) Eastern Mediterranean includes Israel and Cyprus.

(3) Other International includes China and various international new ventures such as offshore Nicaragua and offshore France.

Oil and gas exploration expense for the second quarter and first six months of 2011 included the following:

- dry hole cost associated with exploratory drilling in the US Rocky Mountain area and offshore Senegal and Guinea-Bissau;
- acquisition of seismic information for Wattenberg, Rocky Mountain and deepwater Gulf of Mexico areas in the US, offshore Nicaragua, offshore France, and offshore Cyprus; and
- staff expense associated with new ventures offshore Nicaragua and offshore France.

Oil and gas exploration expense for the second quarter and first six months of 2010 included the following:

- US dry hole cost associated with the Double Mountain exploration well in the deepwater Gulf of Mexico; and
- acquisition of seismic information in the US in support of Central Gulf of Mexico lease sales and in West Africa for Cameroon.

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Depreciation, Depletion and Amortization DD&A expense was as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
DD&A Expense (millions) (1)	$235	$215	$456	$431
Unit Rate per BOE (2)	$12.43	$11.13	$12.12	$11.81

(1)For DD&A expense by geographical area, see Item 1. Financial Statements – Note 14. Segment Information.

(2)Consolidated unit rates exclude sales volumes and expenses attributable to equity method investees.

Total DD&A expense for the second quarter and first six months of 2011 increased as compared with 2010 due to the following:

- higher DD&A expense in the Wattenberg area of our onshore US operations due to higher sales volumes resulting from ongoing capital spending;
- higher DD&A expense in Equatorial Guinea due to higher sales volumes;
- higher DD&A expense in the North Sea due to higher sales volumes and higher costs associated with development activities; and
- higher DD&A expense in China due to higher costs associated with development activities;

partially offset by

- lower DD&A expense in the deepwater Gulf of Mexico, Gulf Coast, and Mid-Continent areas of our US operations due to lower sales volumes resulting from natural field decline; and
- the cessation of DD&A associated with certain Oklahoma and Illinois Basin assets sold during 2010.

Changes in the unit rate per BOE for the second quarter and first six months of 2011 as compared with 2010 were due to changes in the mix of production. For example, sales volumes from Equatorial Guinea and Israel have lower DD&A rates.

General and Administrative Expense General and administrative expense (G&A) was as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
G&A Expense (millions)	$82	$63	$165	$129
Unit Rate per BOE (1)	$4.34	$3.26	$4.38	$3.54

(1) Consolidated unit rates exclude sales volumes and expenses attributable to equity method investees.

G&A expense for the second quarter and first six months of 2011 increased as compared with 2010 primarily due to additional expenses relating to personnel, office, and information technology costs in support of our major development projects and increased exploration activities.

Asset Impairments Asset impairment expense was as follows:

Three Months Ended June 30, Six Months Ended June 30,

		2011		2010		2011		2010
(millions)								
Asset Impairments	$	131	$	-	$	139	$	-

See Item 1. Financial Statements – Note 3. Asset Impairments and Note 6. Fair Value Measurements and Disclosures.

Other Operating (Income) Expense, Net Other operating (income) expense, net was as follows:

	Three Months Ended June 30,				Six Months Ended June 30,			
		2011		2010		2011		2010
(millions)								
Deepwater Gulf of Mexico Moratorium Expense	$	1	$	26	$	19	$	26
Electricity Generation Expense		9		7		26		17
Gain on Divestitures		(25)		-		(26)		-
Other, Net		4		8		(1)		12
Total	$	(11)	$	41	$	18	$	55

See Item 1. Financial Statements – Note 2. Basis of Presentation.

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Other (Income) Expense

Other (income) expense was as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
(millions)				
(Gain) Loss on Commodity Derivative Instruments	$(143)	$(96)	$143	$(242)
Interest, Net of Amount Capitalized	21	19	37	39
Other Non-Operating (Income) Expense, Net	(9)	(13)	-	(13)
Total	$(131)	$(90)	$180	$(216)

(Gain) Loss on Commodity Derivative Instruments (Gain) loss on commodity derivative instruments is a result of mark-to-market accounting. See Item 1. Financial Statements – Note 5. Derivative Instruments and Hedging Activities and Note 6. Fair Value Measurements and Disclosures.

Interest Expense and Capitalized Interest Interest expense and capitalized interest were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
(millions, except unit rate)				
Interest Expense	$49	$35	$90	$70
Capitalized Interest	(28)	(16)	(53)	(31)
Interest Expense, Net	$21	$19	$37	$39
Unit Rate per BOE (1)	$1.13	$0.99	$0.99	$1.06

(1)Consolidated unit rates exclude sales volumes and expenses attributable to equity method investees.

Interest expense increased for the second quarter and first six months of 2011 as compared with 2010. The increase in interest expense resulted from a higher outstanding debt balance during the period and the interest associated with our 6% senior unsecured notes issued in first quarter 2011. The higher rate on the senior unsecured notes replaced the substantially lower rate applicable to our revolving credit facility which was repaid with proceeds from our debt offering. See also Liquidity and Capital Resources – Financing Activities below.

The increase in the amount of interest capitalized is due to higher work in progress amounts related to major long-term projects in the deepwater Gulf of Mexico, West Africa, and Israel and a higher weighted average interest rate associated with our 6% senior unsecured notes, which impacted the average rate we pay on long-term debt.

Other Non-operating (Income) Expense, Net Other non-operating (income) expense, net includes deferred compensation expense, interest income and other (income) expense. See Item 1. Financial Statements – Note 2. Basis of Presentation.

Income Tax Provision

See Current Global Economic Situation, Changes in Fiscal Regimes and Market Regulations, above, and Item 1. Financial Statements – Note 12. Income Taxes for a discussion of the change in our effective tax rate for the first six months of 2011 as compared with 2010.

LIQUIDITY AND CAPITAL RESOURCES

Capital Structure/Financing Strategy

In seeking to effectively fund and monetize our major development projects, we employ a capital structure and financing strategy designed to provide ample liquidity throughout the commodity price cycle. Specifically, we strive to retain the ability to fund long cycle, multi-year, capital intensive development projects while also maintaining the capability to execute a robust exploration program and financially attractive periodic mergers and acquisitions activity. We endeavor to maintain an investment grade debt rating in service of these objectives. We also utilize a commodity price hedging program to reduce commodity price uncertainty and enhance the predictability of cash flows along with a risk and insurance program to protect against disruption to our cash flows and operations.

Traditional sources of our liquidity are cash on hand, cash flows from operations and available borrowing capacity under our credit facility. Occasional sales of non-strategic crude oil and natural gas properties as well as our periodic access to capital markets may also generate cash.

Our financial capacity, coupled with our balanced and diversified portfolio, provides us with flexibility in our investment decisions including execution of our major development projects and increased exploration activity.

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Information regarding cash and debt balances was as follows:

(millions, except percentages)	June 30, 2011	December 31, 2010
Cash and Cash Equivalents	$ 1,527	$ 1,081
Amount Available to be Borrowed Under Credit Facility (1)	2,100	1,750
Total Liquidity	$ 3,627	$ 2,831
Total Debt (2)	$ 2,830	$ 2,279
Total Shareholders' Equity	7,158	6,848
Ratio of Debt-to-Book Capital (3)	28 %	25 %

(1)Our credit facility is committed in the amount of $2.1 billion until December 9, 2011 at which time the commitment reduces to $1.8 billion.

(2)Total debt includes FPSO lease obligation and excludes unamortized debt discount.

(3)We define our ratio of debt-to-book capital as total debt (which includes long-term debt excluding unamortized discount, the current portion of long-term debt, and short-term borrowings) divided by the sum of total debt plus shareholders’ equity.

Cash and Cash Equivalents   We had over $ 1.5 billion in cash and cash equivalents at June 30, 2011, primarily denominated in US dollars and invested in money market funds and short-term deposits with major financial institutions. A majority of this cash is attributable to our foreign subsidiaries and most would be subject to US income taxes if repatriated. We currently intend to use our international cash to fund international programs, including the planned developments in Equatorial Guinea and Israel.

Credit Facility   We have an unsecured revolving credit facility that matures December 9, 2012. The commitment is $2.1 billion until December 9, 2011 at which time the commitment reduces to $1.8 billion. We ended second quarter 2011 with $ 2.1 billion remaining available for borrowing under the current $2.1 billion commitment.

Derivative Instruments   We use various derivative instruments in connection with anticipated crude oil and natural gas sales to minimize the impact of product price fluctuations and ensure cash flow for future capital needs. Such instruments include variable to fixed price commodity swaps, two and three-way collars and basis swaps. Current period settlements on commodity derivative instruments impact our liquidity, since we are either paying cash to, or receiving cash from, our counterparties. If actual commodity prices are higher than the fixed or ceiling prices in our derivative instruments, our cash flows will be lower than if we had no derivative instruments. Conversely, if actual commodity prices are lower than the fixed or floor prices in our derivative instruments, our cash flows will be higher than if we had no derivative instruments. None of our counterparty agreements contain margin requirements. We also use derivative instruments to manage interest rate risk by entering into forward contracts or swap agreements to minimize the impact of interest rate fluctuations associated with fixed or floating rate borrowings.

Commodity derivative instruments are recorded at fair value in our consolidated balance sheets, and changes in fair value are recorded in earnings in the period in which the change occurs. As of June 30, 2011 the fair value of our commodity derivative assets was $ 5 million and the fair value of our commodity derivative liabilities was $ 180 million (after consideration of netting agreements). See Item 1. Financial Statements – Note 5. Derivative Instruments and Hedging Activities for a discussion of counterparty credit risk and Note 6. Fair Value Measurements and Disclosures for a description of the methods we use to estimate the fair values of derivative instruments.

Contractual Obligations

In February 2011, we completed an underwritten public offering of $850 million, 6% senior unsecured notes due March 1, 2041. See Financing Activities below.

Based on the total debt balance, scheduled maturities and interest rates in effect at June 30, 2011, future long-term payments of principal (excluding our FPSO lease obligation) and interest are as follows:

Obligation (millions)	Total	2011	2012 and 2013	2014 and 2015	2016 and beyond
Long-Term Debt (1)	$2,484	$-	$-	$200	$2,284
Cash Payments for Interest	3,142	89	355	339	2,359

(1) Long-term debt excludes FPSO lease obligation.

See Item 1. Financial Statements – Note 4. Debt for estimated future FPSO lease payments at June 30, 2011.

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Cash Flows

Cash flow information is as follows:

	Six Months Ended June 30,	
(millions)	2011	2010
Total Cash Provided By (Used in)		
Operating Activities	$1,229	$844
Investing Activities	(1,184)	(1,248)
Financing Activities	401	407
Increase in Cash and Cash Equivalents	$446	$3

Operating Activities   Net cash provided by operating activities for the first six months of 2011 increased as compared with 2010 primarily due to higher revenues, which benefitted from increases in commodity prices and lower exploration expenditures. The increase in cash flow was partially offset by increases in general and administrative expense, interest expense, and tax payments. See Item 1. Financial Statements – Consolidated Statements of Cash Flows.

Investing Activities   Our investing activities include capital spending on a cash basis for oil and gas properties, which may be offset by proceeds from property sales or dispositions. Capital spending for property, plant and equipment increased by $ 479 million during the first six months of 2011 as compared with 2010, primarily due to increased major project development activity in the Wattenberg area, offshore West Africa, and offshore Israel, and was offset by $77 million proceeds from divestitures of non-core assets including our Ecuador assets and certain onshore US assets. Additional investing activities for 2010 included $466 million related to the Central DJ Basin asset acquisition.

Financing Activities   Our financing activities include the issuance or repurchase of our common stock, payment of cash dividends on our common stock, the borrowing of cash and the repayment of borrowings. During the first six months of 2011, funds were provided by net cash proceeds from borrowings under our revolving credit facility ($120 million) and the issuance of 6% senior notes ($836 million). Funds were also provided by cash proceeds from, and tax benefits related to, the exercise of stock options ($35 million). We used a portion of the proceeds from the issuance of senior notes to repay amounts outstanding under our credit facility ($470 million). We also used cash to settle an interest rate lock ($40 million), pay dividends on our common stock ($64 million) and repurchase shares of our common stock ($16 million).

In comparison, during the first six months of 2010, $438 million of funds were provided by net increases in borrowings under our revolving credit facility and used to fund the Central DJ Basin asset acquisition and other capital expenditures. Funds were also provided by cash proceeds from, and tax benefits related to, the exercise of stock options ($44 million). We used cash to pay dividends on our common stock ($63 million) and repurchase shares of our common stock ($12 million).

See Item 1. Financial Statements – Consolidated Statements of Cash Flows.

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Investing Activities

Acquisition, Capital and Exploration Expenditures Information for investing activities (on an accrual basis) is as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
(millions)				
Acquisition, Capital and Exploration Expenditures				
Unproved Property Acquisition	$42	$62	$57	$208
Proved Property Acquisition	-	-	-	363
Exploration (1)	106	56	228	171
Development	500	363	874	637
Corporate and Other	54	38	88	58
Total	$702	$519	$1,247	$1,437
Increase in FPSO Lease Obligation	$17	$68	$51	$108

(1) Amount for three and six months ended June 30, 2011 is net of probable insurance proceeds totaling $25 million which relates to our Leviathan #2 appraisal well offshore Israel.

2011 Unproved property acquisition costs include amounts related to our new position offshore Senegal and Guinea-Bissau (the AGC Profond block) as well as miscellaneous onshore US lease acquisitions. The increase in development costs is due to increased capital spending on major development projects located in the DJ Basin, offshore Equatorial Guinea and offshore Israel.

2010 Unproved property acquisition costs included $36 million for lease bonuses paid on deepwater Gulf of Mexico lease blocks, $146 million related to the Central DJ Basin asset acquisition, and the remainder primarily for other onshore US lease acquisitions. Proved property acquisition costs related to the Central DJ Basin asset acquisition.

FPSO Lease Obligation The FPSO lease obligation represents the increase in estimated construction in progress to date on an FPSO to be used in the development of the Aseng field in Equatorial Guinea. See Item 1. Financial Statements – Note 4. Debt.

Financing Activities

Credit Facility Our principal source of liquidity is an unsecured revolving credit facility that matures December 9, 2012. The commitment is $2.1 billion until December 9, 2011 at which time the commitment reduces to $1.8 billion. The credit facility (i) provides for credit facility fee rates that range from 5 basis points to 15 basis points per year depending upon our credit rating, (ii) makes available short-term loans up to an aggregate amount of $300 million within the current $2.1 billion commitment and (iii) provides for interest rates that are based upon the Eurodollar rate plus a margin that ranges from 20 basis points to 70 basis points depending upon our credit rating and utilization of the credit facility. The credit facility is with certain commercial lending institutions and is available for general corporate purposes.

In order to provide increased liquidity and lengthen our weighted average debt maturity, on February 18, 2011 we completed an underwritten public offering of $850 million of 6% senior unsecured notes due March 1, 2041, receiving net proceeds of $836 million after deducting discount and underwriting fees. Approximately $470 million of the net proceeds were used to repay outstanding indebtedness under our revolving credit facility maturing 2012 and the balance of the proceeds will be used for general corporate purposes.

At June 30, 2011, there were no borrowings outstanding under the credit facility, leaving the entire $2.1 billion available for use. We periodically borrow amounts under provision (ii) above for working capital purposes.

Fixed-Rate Debt   Our outstanding fixed-rate debt totaled almost $2.5 billion at June 30, 2011. The weighted average interest rate on fixed-rate debt was 7.14%, with maturities ranging from 2014 to 2097. Only 8% of our fixed rate debt matures within the next five years.

FPSO Lease Obligation   We have an agreement for the construction and lease of an FPSO to be used for development of the Aseng field, offshore Equatorial Guinea. The FPSO is currently under construction, and we are including the FPSO lease obligation in our balance sheet based upon the percentage of construction completed at the end of each reporting period. The obligation increased $51 million during the first six months of 2011. We currently expect Aseng production to commence at year end 2011.

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Ratio of Debt-to-Book Capital Our ratio of debt-to-book capital was 28% at June 30, 2011 as compared with 25% at December 31, 2010. We define our ratio of debt-to-book capital as total debt (which includes long-term debt excluding unamortized discount, the current portion of long-term debt, and short-term borrowings) divided by the sum of total debt plus shareholders' equity.

Other Short-Term Borrowings Our committed credit facility may be supplemented by short-term borrowings under various uncommitted credit lines used for working capital purposes. Uncommitted credit lines may be offered by certain banks from time to time at rates negotiated at the time of borrowing. There were no amounts outstanding under uncommitted credit lines at June 30, 2011 or December 31, 2010, nor did we borrow any funds under uncommitted credit lines during the first six months of 2011. Depending upon future credit market conditions, these sources may or may not be available. However, we are not dependent on them to fund our day-to-day operations.

A failure by the U.S. Congress to lift the debt ceiling or a downgrade of U.S. Sovereign debt could result in incrementally higher term borrowing costs. Higher treasury yields are likely to result from any default scenario or from events that ultimately lead to a ratings downgrade and the loss of AAA sovereign debt status. Inasmuch as U.S. Treasury yields serve as the risk-free rate and function as a base rate for U.S. dollar based lending rates, higher treasury yields would likely translate into higher long term borrowing costs for all corporations. Our short term financing costs could also rise if it becomes more expensive for our banks to source Libor based funding via the interbank loan market.

Dividends We paid total cash dividends of 36 cents per share of our common stock during the first six months of each of 2011 and 2010. On July 26, 2011, our Board of Directors declared a quarterly cash dividend of 22 cents per common share, payable August 22, 2011 to shareholders of record on August 8, 2011. The amount of future dividends will be determined on a quarterly basis at the discretion of our Board of Directors and will depend on earnings, financial condition, capital requirements and other factors.

Exercise of Stock Options We received cash proceeds from the exercise of stock options of $26 million during the first six months of 2011 and $28 million during the first six months of 2010.

Common Stock Repurchases We receive shares of common stock from employees for the payment of withholding taxes due on the vesting of restricted shares issued under stock-based compensation plans. We received 180,538 shares with a value of $16 million during the first six months of 2011 and 163,388 shares with a value of $12 million during the first six months of 2010.

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Item 3. Quantitative and Qualitative Disclosures About Market Risk

Commodity Price Risk

Derivative Instruments Held for Non-Trading Purposes We are exposed to market risk in the normal course of business operations, and the uncertainty of crude oil and natural gas prices continues to impact the oil and gas industry. Due to the volatility of crude oil and natural gas prices, we continue to use derivative instruments as a means of managing our exposure to price changes.

At June 30, 2011, we had entered into variable to fixed price commodity swaps, collars and basis swaps related to crude oil and natural gas sales. Changes in fair value of commodity derivative instruments are reported in earnings in the period in which they occur. Our open commodity derivative instruments were in a net payable position with a fair value of $175 million. Based on the June 30, 2011 published commodity futures price strips for the underlying commodities, a hypothetical price increase of $1.00 per Bbl for crude oil would increase the fair value of our net commodity derivative payable by approximately $20 million. A hypothetical price increase of $0.10 per MMBtu for natural gas would increase the fair value of our net commodity derivative payable by approximately $9 million. Our derivative instruments are executed under master agreements which allow us, in the event of default, to elect early termination of all contracts with the defaulting counterparty. If we choose to elect early termination, all asset and liability positions with the defaulting counterparty would be net cash settled at the time of election. See Item 1. Financial Statements – Note 5. Derivative Instruments and Hedging Activities.

Interest Rate Risk

Changes in interest rates affect the amount of interest we pay on borrowings under our revolving credit facility and the amount of interest we earn on our short-term investments.

At June 30, 2011, we had almost $2.5 billion (excluding the FPSO lease obligation and unamortized debt discount) of long-term debt outstanding. All debt outstanding was fixed-rate debt with a weighted average interest rate of 7.14%. Although near term changes in interest rates may affect the fair value of our fixed-rate debt, they do not expose us to the risk of earnings or cash flow loss. See Item 1. Financial Statements – Note 4. Debt.

We occasionally enter into interest rate derivative instruments such as forward contracts or swap agreements to hedge exposure to interest rate risk. Changes in fair value of interest rate derivative instruments used as cash flow hedges are reported in AOCL, to the extent the hedge is effective, until the forecasted transaction occurs, at which time they are recorded as adjustments to interest expense. At June 30, 2011, AOCL included $27 million, net of tax, related to interest rate derivative instruments. This amount is currently being reclassified to earnings as adjustments to interest expense over the terms of our 5¼% senior notes due April 2014 and 6% senior notes due March 1, 2041. See Item 1. Financial Statements – Note 5. Derivative Instruments and Hedging Activities.

We are also exposed to interest rate risk related to our interest-bearing cash and cash equivalents balances. As of June 30, 2011, our cash and cash equivalents totaled $ 1.5 billion, approximately 70% of which was invested in money market funds and short-term investments with major financial institutions. A hypothetical 25 basis point change in the floating interest rates applicable to the amount invested as of June 30, 2011 would result in a change in annual interest income of approximately $3 million.

Foreign Currency Risk

The US dollar is considered the functional currency for each of our international operations. Substantially all of our international crude oil, natural gas and NGL production is sold pursuant to US dollar denominated contracts.

Transactions, such as operating costs and administrative expenses that are paid in a foreign currency, are remeasured into US dollars and recorded in the financial statements at prevailing currency exchange rates. Certain monetary assets and liabilities, such as foreign deferred tax liabilities in certain foreign tax jurisdictions, are denominated in a foreign currency. A reduction in the value of the US dollar against currencies of other countries in which we have material operations could result in the use of additional cash to settle operating, administrative, and tax liabilities. This risk may be mitigated to the extent commodity prices increase in response to a devaluation of the US dollar.

Transaction gains or losses were not material in any of the periods presented and are included in other (income) expense, net in the consolidated statements of operations.

We currently have no foreign currency derivative instruments outstanding. However, we may enter into foreign currency derivative instruments (such as forward contracts, costless collars or swap agreements) in the future if we determine that it is necessary to invest in such instruments in order to mitigate our foreign currency exchange risk.

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Disclosure Regarding Forward-Looking Statements

This quarterly report on Form 10-Q contains forward-looking statements within the meaning of the federal securities laws. Forward-looking statements give our current expectations or forecasts of future events. These forward-looking statements include, among others, the following:

- our growth strategies;
- our ability to successfully and economically explore for and develop crude oil and natural gas resources;
- anticipated trends in our business;
- our future results of operations;
- our liquidity and ability to finance our exploration and development activities;
- market conditions in the oil and gas industry;
- our ability to make and integrate acquisitions;
- the impact of governmental fiscal terms and/or regulation, such as that involving the protection of the environment or marketing of production as well as other regulations; and
- access to resources.

Forward-looking statements are typically identified by use of terms such as “may,” “will,” “expect,” “believe,” “anticipate,” “estimate,” “intend,” and similar words, although some forward-looking statements may be expressed differently. These forward-looking statements are made based upon our current plans, expectations, estimates, assumptions and beliefs concerning future events impacting us and therefore involve a number of risks and uncertainties. We caution that forward-looking statements are not guarantees and that actual results could differ materially from those expressed or implied in the forward-looking statements. You should consider carefully the statements under Item 1A. Risk Factors included herein, if any, and included in our Quarterly Report on Form 10-Q for the quarter ended March 31, 2011, and our Annual Report on Form 10-K for the year ended December 31, 2010, which describe factors that could cause our actual results to differ from those set forth in the forward-looking statements. Our Annual Report on Form 10-K for the year ended December 31, 2010 is available on our website at www.nobleenergyinc.com.

Item 4. Controls and Procedures

Based on the evaluation of our disclosure controls and procedures by our principal executive officer and our principal financial officer, as of the end of the period covered by this quarterly report, each of them has concluded that our disclosure controls and procedures, as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended, are effective. There were no changes in internal control over financial reporting that occurred during the quarter covered by this report that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Part II. Other Information

Item 1. Legal Proceedings

See Item I. Financial Statements – Note 15. Commitments and Contingencies.

Item 1A. Risk Factors

There have been no material changes from the risk factors disclosed in Item 1A. Risk Factors of our Quarterly Report on Form 10-Q for the quarter ended March 31, 2011 or our Annual Report on Form 10-K for the year ended December 31, 2010.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

Period	Total Number of Shares Purchased (1)	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs (in thousands)
04/01/11 - 04/30/11	683	$ 95.49	-	-
05/01/11 - 05/31/11	565	91.46	-	-
06/01/11 - 06/30/11	791	88.82	-	-
Total	2,039	$ 91.78	-	-

(1)Stock repurchases during the period related to stock received by us from employees for the payment of withholding taxes due on shares issued under stock-based compensation plans.

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Item 3. Defaults Upon Senior Securities

None.

Item 4. (Removed and Reserved)

Item 5. Other Information

None.

Item 6. Exhibits

The information required by this Item 6 is set forth in the Index to Exhibits accompanying this quarterly report on Form 10-Q.

Signatures

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

NOBLE ENERGY, INC.
(Registrant)

Date July 28, 2011

/s/ Kenneth M. Fisher
Kenneth M. Fisher
Senior Vice President, Chief Financial Officer

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Index to Exhibits

Exhibit Number	Exhibit
3.1	Certificate of Incorporation, as amended through May 16, 2005, of the Registrant (filed as Exhibit 3.1 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2008, and incorporated herein by reference).
3.2	By-Laws of Noble Energy, Inc. as amended through June 1, 2009 (filed as Exhibit 3.1 to the Registrant's Current Report on Form 8-K (Date of Event: February 17, 2009) filed February 20, 2009 and incorporated herein by reference).
31.1	Certification of the Company's Chief Executive Officer Pursuant To Section 302 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 7241), filed herewith.
31.2	Certification of the Company's Chief Financial Officer Pursuant To Section 302 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 7241), filed herewith.
32.1	Certification of the Company's Chief Executive Officer Pursuant To Section 906 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 1350), filed herewith.
32.2	Certification of the Company's Chief Financial Officer Pursuant To Section 906 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 1350), filed herewith.
101.INS	XBRL Instance Document
101.SCH	XBRL Schema Document
101.CAL	XBRL Calculation Linkbase Document
101.LAB	XBRL Label Linkbase Document
101.PRE	XBRL Presentation Linkbase Document
101.DEF	XBRL Definition Linkbase Document